COMMITTEE HEARING

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	
Preparation of the 2005 Integrated Energy Policy Report	Docket No. 04-IEP-1K
Re: Availability of the 2005 Committee Draft Energy Report.	
Electricity Needs and Procurement Policies (Chap 3) Transmission Challenges (Chap 5)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

FRIDAY, OCTOBER 7, 2005

9:05 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

Joseph Desmond, Chairperson

ADVISORS PRESENT

Michael Smith

Melissa Jones

STAFF and CONTRACTORS PRESENT

Kevin Kennedy

Lynn Marshall

ALSO PRESENT

Robert Freehling
Local Power

Barbara George
Women's Energy Matters

Steven Kelly
Independent Energy Producers Association

Gregory T. Blue
Dynegy, Inc.
representing West Coast Power

Gary Ackerman
Western Power Trading Forum

Robert Anderson
San Diego Gas and Electric Company

Jane Turnbull
League of Women Voters of California

Audrey Chang
Natural Resources Defense Council

ALSO PRESENT

Alvin Pak
Sempra Energy Global Enterprises
Sempra Utilities

Bruce McLaughlin, Attorney
Braun & Blaising, PC
representing California Municipal Utilities
Association

Stuart Hemphill
Southern California Edison Company

I N D E X

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P R O C E E D I N G S

9:05 a.m.

PRESIDING MEMBER GEESMAN: We've got a variety of things to do today. Firstly, this is day 58 of the IEPR process. I'm John Geesman, the Presiding Member of the IEPR Committee. To my left, Commissioner Jim Boyd, the Associate Member. to my far right, Joe Desmond, the Commission's Chair. To my immediate right, Melissa Jones, my Staff Advisor.

Today we have two topics. One being the electricity demand forecast and associated supply issues. The second being the same issues regarding natural gas.

What we're going to try and do is defer the natural gas issues until the afternoon. But I want to leave open the possibility that some of the electricity issues may spill over into the afternoon, as well, because of the indulgence of many of you of my schedule yesterday. We'll go as long as we need to today to finish up the discussion of each of our topics.

We do have a couple of holdovers from yesterday. And because they graciously agreed to defer their comments until today, I want to start

today's hearing, before we have the staff presentations, with a continuation of yesterday's discussion.

First up is Mr. Freehling from Local Power.

MR. FREEHLING: Good morning and thank you, Commissioners.

Local Power is concerned with the other side of the system than the one that mostly has been discussed and will be discussed today. We're interested in the side that's on the distribution end.

And what we'd like to see at Local Power is the distribution end of the electricity system become a real resource. At the moment there are a lot of impediments to making this happen. Part of it, of course, is that we're thinking in terms of supply for the electricity system. We're thinking in terms of building more generators on the other end of the distribution system, at the other end of the transmission system. That means you have to build more transmission lines; that means you have to build more power plants.

The problem with that model is that when you place a power plant on the other end of a

transmission system, you have line losses between the generator and the point of consumption. That's one problem. Another problem is that you have to build very expensive transmission lines.

These two costs create a burden on the system that can be lifted to some extent by placing resources on the other end, on the distribution end. And there's some of these benefits that are obvious and well known. Some of these are maybe perhaps not quite so well known.

It's on this basis that I disagree partly with the analysis given yesterday on the question of comparing combined heat and power with a combined cycle generator.

If combined heat and power is placed on the distribution end of the system as part of distributed generation it doesn't exhibit the line losses which, in California, amount to over 8 percent, at least according to most of the estimates that are circulated at the Energy Commission. That's a huge amount of electricity that's lost.

So any resource that's placed on the distribution end is going to immediately likely save about 8 percent of the power. And it could

actually do significantly better than this.

Recent study by Tom Hoff for the Sacramento Municipal Utility District, which we're located in, showed that distributed power, when it's placed on a distribution network, can actually avoid losses in the distribution system for that entire local distribution branch. And not just simply the losses that would have happened because of the power generation being sent over the lines. It's like it's being held up on the other end of the board, not just on the other end of the transmission line. So you've got two ends that support the system.

So, there's a tremendous potential for saving energy, and one could, in fact, say that placing distribution resources, generation resources is actually an energy efficiency measure as much as it is a generation measure.

Now, there's several barriers that happen when we place distributed generation on the system. One of these, of course, is that our priority is to place renewables on that end. And some of these renewables are well known to be intermittent in generation. And some of them are even more intermittent, such as wind generation

when they're placed, for example, in the city than when they're placed on a large windfarm under optimal wind conditions.

So, intermittency is often more of a problem in an urban environment, say where the demand load is heavy, than where it would be -- where it's placed on the other end of the transmission system.

Another problem with distributed power is that many of these distributed resources are not measured. And this has to do partly with the method in which we use to meter. Net metering, for example, which is placed on a PV system on a home or on a commercial site, does not measure the independent production of a PV system. So that PV system actually disappears behind the wall of this net meter.

This is one of the things that I found very exciting yesterday about the discussion of putting smarter meters on homes and businesses so that the meter could actually do more things.

A meter, for example, that could measure the independent production of a demand side resource would allow that resource to become real and visible on the system as opposed to one that

net meters only, where it erases the production record of that resource on the system.

Now, these barriers -- excuse me, I have to take off my glasses because I can't see up close with them on -- are further complicated by the fact that the rules that are set up for implementing distributed generation, as well as energy efficiency on the customer's end, are placed on a site-by-site basis.

In other words, when you have a rule that says that one PV system is going to be tied to one meter, which is the onsite requirement that's currently the rules and was going to be reinforced by the million solar roofs bill, which did not pass, and also by the renewable portfolio standard bill, a concern of Local Power's was that that was also going to be put in place.

We'd like to see that not in place because the ability to cooperate between different resources on the demand end would give it the edge that is given on the other end to renewable resources.

Yesterday there was a woman from the wind industry who spoke about how intermittency of wind generation is not really a problem anymore.

Now, she didn't describe why it wasn't a problem, but there are a number of solutions that are available in the wind industry which are not given on the customer's end of the deal.

One of these is the ability of one windmill on a farm to cooperate with another windmill on a farm. And it's well known that the further out you distribute windmills the more they're able to even out the irregularities of the performance of the other windmills.

So, by allowing the coordination of these resources they can balance out the production of the system as a whole. This coordination is currently not allowed in the system, for example implementing photovoltaics as a distributed resource, or wind power as a distributed resource. There's no coordination in the system. It's whoever happens to buy a PV system.

I'm not saying you shouldn't allow that, but some measure of integrating that system, both in terms of measuring what the output is, and also looking in terms of where and how can we strategically place these resources, and perhaps even prefer to place these resources using the

systems of subsidies that are at your disposal, such that it supports the grid in the optimal way. And such that each of these resources is actually working together with the others.

PRESIDING MEMBER GEESMAN: Would you see that integration task as a utility function, or do you have something else in mind?

MR. FREEHLING: Well, Local Power is responsible for bringing community choice to California. And so one of the main reasons why all these things have come to my table is because I've been considering how, for example, San Francisco can integrate distributed resources into its system.

And one-by-one I confront the barriers and impediments that are built into the rules and regulations of the state. For example, -- well, to answer your question I would not want to see only one model in place for this.

I think that what needs to happen for community choice, in any case, is to see the possibility of integrating the pieces of the puzzle together.

And I'd like to describe other elements that --

PRESIDING MEMBER GEESMAN: Okay.

MR. FREEHLING: -- I see, as well. But the idea is to build actually an urban network of coordinated solar systems, as well as urban wind to the extent that that may be possible; tidal, as well as energy efficiency and conservation measures.

PRESIDING MEMBER GEESMAN: But I guess my question is coordinated by a single coordinator within, let's say a community choice jurisdiction? Or coordinated by dozens of independent generators fashioning partnerships?

MR. FREEHLING: Yeah, ideally I'd like to see that -- we'd like to see that integrated by the community choice aggregation --

PRESIDING MEMBER GEESMAN: Okay.

MR. FREEHLING: -- or by the electric service provider if they happen to be doing the system planning. There are different models under which community choice can be implemented in that respect.

PRESIDING MEMBER GEESMAN: But you concept from an engineering standpoint is a single coordinator in a particular service territory?

MR. FREEHLING: Yes. And for IOUs I see

absolutely no reason why that kind of resource integration couldn't happen on their end, as well.

Now, some of these would challenge some of the ownership and subsidy models that have been put in place.

PRESIDING MEMBER GEESMAN: What --

MR. FREEHLING: Well, for example, a model that was implemented by SMUD that was quite successful in the pioneer 1 program was actually having the utility own the PV systems on the roof. And this was a way to make PV, which was an expensive resource for many householders to afford, affordable by allowing them to either lease it from the utility or essentially buy photovoltaic electricity at the price of electricity. Even if that's at a premium, that makes it much more affordable to an individual to pay, even if it's 50 cents a kilowatt hour, it's more affordable to any person in society than it would be to go out and plunk down $20,000 or more on a PV system.

PRESIDING MEMBER GEESMAN: And what concept does that challenge?

MR. FREEHLING: The current rebate systems, for example, are --

PRESIDING MEMBER GEESMAN: Okay.

MR. FREEHLING: -- structured so that those kinds of ownership models would not be rewarded with a rebate.

PRESIDING MEMBER GEESMAN: It challenges the principle that all government programs are fated to never change or evolve with changing needs.

MR. FREEHLING: Yeah, I suppose that would be one way of putting it.

(Laughter.)

MR. FREEHLING: Another issue that I was mentioning here was the coordination -- is expanding that coordination between resources. The intermittency of wind and particularly solar power, means that in order to create a valuable resource that actually fits within the electricity system, you need to be able to firm that capacity.

And there are a number of ways of doing that. NREL created a report, actually, where they analyzed the case of California of implementing a few gigawatts of solar power.

And they showed that one of the things that could be done in order to firm capacity of solar would be to put a regulating device on the

electricity system so that if a cloud passed over a building, for example, it would cut out the air conditioner for the 15 minutes that the cloud was passing over.

So you'd coordinate the demand restriction with the demand controls with the production of the PV system output, which would limit the negative effects of either one. So that you're not necessarily turning off an air conditioner for hours and hours in a day when it's sunny or hot, which is when a commercial or residential customer doesn't want that air conditioner turned off.

And it would turn off the air conditioning load or reduce it during the time when the sun was gone, which is a time which would probably be more amenable to doing so.

So this was just sort of a key example of how to drawn connecting links between pieces of the distributed end of the network that could be extended quite far beyond just simply, for example, connecting the air conditioning load with the PV system.

PRESIDING MEMBER GEESMAN: Commissioner Desmond, did you have a question?

CHAIRPERSON DESMOND: Just wanted to provide some sources of information, I guess, regarding the notion of coordination.

One, that effort is currently underway, what you're asking or describing, both. EPRI had done some work with the Department of Energy through its gridwise alliance, in fact is focused on things like the self-healing grid, distributed intelligent agents, microgrids and just recognizing the implication is a requirement for real-time information exchange, --

MR. FREEHLING: Right.

CHAIRPERSON DESMOND: -- which is going to add a layer of cost onto that. Some of that work being done really deals with autonomous intelligent agent networks responding to either opportunities to optimize against price reliability.

And so I think, again, my only comment is I think we could probably make reference to what's happening at the Department of Energy in that area that would help capture some of that.

MR. FREEHLING: Well, you saved me from saying anything on that. Microgrids was, in fact, one of the things that I wanted to add, certainly,

as a possibility. And these are not necessarily supported by the legislation that has been put through recently with a million solar roofs bill, for example, which reinforced the onsite requirement. And as did the renewable portfolio standard bill that was recently put through.

And I think that at least it's necessary to remove the barriers to performing these things one by one. And the ability to implement and measure these things will grow as the sophistication of electronics progresses, if smart meters, for example, are placed on sites that actually have the ability to monitor these things.

Some of these are already existing in current inverters, for example, for photovoltaics, an option exists to place real-time monitoring. You don't need to have down to the last, you know, milliwatt in any case. Something that's close to within, you know, 5 percent, for example, of the production of any given PV system, as long as PV is representing less than 1 percent of the grid, in any case, is probably sufficient to get an idea of what it's contributing.

I'm sorry, did you have something to ask?

PRESIDING MEMBER GEESMAN: I'm not clear on why you think the million solar roofs initiative created a barrier.

MR. FREEHLING: It created a barrier to the extent that it reinforced the onsite rule. In other words, --

PRESIDING MEMBER GEESMAN: The onsite --

MR. FREEHLING: -- one PV system attached to one meter. And that does not allow for the coordination so easily between different pieces. And there are many ways in which the pieces of the puzzle can be put together.

One of them, for example, could be to implement community solar. And this is something that has been done successfully in other places.

It, one, creates greater affordability. Someone can buy a share in a community solar system. It also allows for a larger scale PV system to be built in a community and integrated. And if one PV system has to be tied on one roof, that creates a barrier to that kind of coordination.

PRESIDING MEMBER GEESMAN: Okay.

MR. FREEHLING: So there are many pathways of coordination. And you have to be

careful that you're not cutting off this one over here and this one over here.

There's so many places in the point where it does that if you just look at one and say, well, we can coordinate a building's air conditioning load with its PV system. That could be done, but that's just one piece. There are 20 different pieces that could potentially be assembled.

For example, another way to firm up capacity would be to coordinate with a cogeneration combined heat and power unit that's maybe a block away on the same distribution system.

Another way that has been proposed that I discussed with the woman yesterday who spoke near the end from EPRI, was devised by them with Southern California Edison, was to have capacity contracts actually with customers. So that if they had a PV system they would agree that they were going to remove a certain amount of load during certain hours of the year when it was critical.

So there are a lot of tools that could be potentially used. And what I'm suggesting is

that the barriers, one by one, to these not only be lifted, but that perhaps the incentive structure, itself, that is created, either through rebates, through SEP payments, and so forth could -- or rewards for, or punishments for failure to meet the renewable portfolio standard, these tools that are available to state regulatory bodies could be put in place to reinforce the structure of what exists on the demand under the equation.

So, and this bring me to the next subject.

PRESIDING MEMBER GEESMAN: Let me say something --

MR. FREEHLING: I'm sorry, go --

PRESIDING MEMBER GEESMAN: -- with regard to that that you and your fellow community choice aggregators may want to ruminate on.

Those models or efforts on the part of the state are probably most effectively created not in the abstract, but in response to a specific application or proposal.

And, you know, a lot of our problems do devolve into a chicken-and-egg metaphor, but I think that particularly with the level of

experimentation and innovation going on at the local level now, perhaps the best way to put some flesh to these skeletal concepts would be to have some proposals made. And hopefully we can design a system flexible enough in terms of incentives, that can accommodate a full range of proposals.

MR. FREEHLING: This, with both incentives and in terms of the rules, regarding allowing, for example, more flexibility with the onsite metering requirements. I was very pleased to see this actually placed in the report this year. The staff actually did bring this forward about how important it is to remove this onsite restriction.

And I feel that that should be underlined and read, put in red and brought to the front, as a major policy issue, not just only for its own sake, but for looking at how new laws that are put into place can facilitate this kind of coordination, so at least that's not a barrier.

There are certainly technical issues which need to be addressed. But they're not going to be addressed if there are major legal and regulatory impediments.

One of the other elements --

PRESIDING MEMBER GEESMAN: Commissioner Desmond.

CHAIRPERSON DESMOND: Just as sort of again, simplify this down into something. What you want to make clear is that distributed generation systems behind the customer's meter ought to have separate metering which would enable the flexible options you've described.

MR. FREEHLING: To the extent that it's economically and rationally feasible. And it may turn out that large commercial customers are the best ones to do that at. And as rebates decrease and tax benefits for commercial entities increase, radically, which they are in the next couple of years, the shift in megawattage demand may turn more and more towards the commercial entities anyway. And in some districts they're paying the highest rates anyway, particularly the small commercial customers.

The economics of placing a smart meter and also implementing demand controls may be much better for those than for, say, a small residential application. And so it may be wise to look at what parts of the system is it best to implement these things.

That's where it's -- you know, one can take a systems approach and look where is it rational to put these into effect. And not simply say across the board it's always going to be correct.

This is actually another issue we had with the million, so I don't want to bash the million solar roofs bill, but the emphasis on residential solar is a problem. Because first of all, the demand is shifting more and more towards commercial solar. And there are tremendous benefits that can be juiced out of commercial solar that are a little more difficult to juice out of a residential system.

Another issue I wanted to raise was regarding the renewable portfolio standard and what counts towards it. In some states distributed photovoltaics actually count towards the utilities' renewable portfolio standard.

One of the problems that utilities have with distributed energy is that they consider it to be a cost burden that's placed on them. By having it included in some sort of benefit towards the utilities and renewable portfolio standards, just one of those tools that could represent a

benefit to the utility or to the community choice aggregators, as the case may be. Counting distributed resources would help push that over the limit, particularly if the RPS is backed up by the penalty of a certain number of cents per kilowatt hour for not being enforced, or for not being carried out.

That resource, then, would have a motivation, an economic benefit to the utility. They would say, rather than, well, that's costing us a couple cents a kilowatt hour that we're not recouping in costs for the transmission system, for example. Or that we're not recouping on other things.

If we're selling electricity onsite at the cost of electricity, at the full retail value, then that could be a problem for a utility. It could be a problem for a community choice aggregator, as well, except that the community choice aggregator is an aggregation of customers.

So there's an integration of interest that's a little different than the utility system.

Nevertheless, if we're going to have, in a community choice aggregation, a variety of ownership options for, say, photovoltaics or other

distributed energy, one of those ownership options might be that the customer owns that personally. Is that going to count towards the RPS.

Well, if it's not, then maybe the community choice aggregator doesn't have any interest in facilitating the ownership by a private entity, just like the utility is put in the same boat. That there's a disincentive for facilitating that interconnection facilitating that policy.

So changing the RPS rules as they are is not only, for example, in New Mexico do they count photovoltaics as qualifying for the RPS, but they are considering it as being a multiple value. So that a megawatt hour of photovoltaic actually counts threefold, because it's considered to have an extra value at the peak hours.

So, an RPS consideration there would be an integration of policies between different segments and pieces. And that, to me, is perhaps the most important sort of over-arching point that I guess I have to make of all.

Is the lesson with regard to the million solar roofs bill is that it is carrying forward a policy that was created -- a number of policies

that were created when the Energy Commission first installed the program. Which was prior to the California energy crisis, prior to the renewable portfolio standard, prior to some of the modern payment systems that are going on and so forth.

And what we would like to see is an integration of these elements, putting them together so that one piece supports the next and is not compartmentalized and segmented in policy.

And the renewable portfolio standard is one way to do that.

Another portion -- and then I'll try and wrap up quickly. I don't want to overdo my welcome here -- is the consideration of energy efficiency and conservation. And there's a major effort in San Francisco, we would like to see a large amount of energy conserved and saved through energy efficiency program.

And this is an example of another potentiality for coordination between other policies. For example, is an energy efficiency measure to be counted towards itself, the renewable portfolio standard.

And while at first glance you might say, well, that's just, you know, out of the question,

we're not going to do that. Of course, some of the methods of generation, themselves, are energy efficiency.

So, combined heat and power, for example, is saving a resource of fuel that by raising the efficiency, average efficiency of the system maybe is 30, 35 percent, can be raising the usage of the natural gas to 60 to 90 percent. So here we have a generation facility that's actually doing energy efficiency.

On the other hand you can have an energy efficiency measure which is actually doing the equivalent of generation.

So that, for example, if a megawatt hour or a gigawatt hour, depending on what scale you want to think of it, is saved, that's a gigawatt hour of electricity that does not have to be procured.

Given that you have a 20 percent RPS, one could say, in the abstract, the 20 percent of that would have had to have been procured as part of the renewable standard.

So, actually at a certain level, without making it explicit policy, there's an implicit coordination between the energy efficiency

measure, which is worth 20 percent of its value one could say in this general way, towards the renewable portfolio standard.

Are you following --

PRESIDING MEMBER GEESMAN: Yeah, the State of Nevada --

MR. FREEHLING: -- my point at all?

PRESIDING MEMBER GEESMAN: -- has adopted that. We're familiar with the energy efficiency angle on RPS.

MR. FREEHLING: Right, right. So, one of the things that would facilitate then this, again from the utility standpoint, as well as from a community choice aggregator standpoint, would be to implement this kind of a concept.

So, that was the main of what I had to say. I hope that's --

PRESIDING MEMBER GEESMAN: Thank you very much.

MR. FREEHLING: Thank you. All right.

PRESIDING MEMBER GEESMAN: And thank you again for deferring your remarks to today.

MR. FREEHLING: I appreciate it.

ASSOCIATE MEMBER BOYD: I want to thank you for your testimony. I found it very

intriguing. It does demand a degree of sophistication that it's hard for the collective us to deal with sometimes. But it is very interesting. And the collective part of that is a little scary sometimes.

But, in any event, you gave us a lot of ideas, thank you.

MR. FREEHLING: Thank you. I appreciate it.

PRESIDING MEMBER GEESMAN: Next up from yesterday is Barbara George, Women's Energy Matters.

MS. GEORGE: Good morning, Commissioners. My name is Barbara George; I'm with Women's Energy Matters. And I have some comments initially I'd like to make on the subject of the electricity procurement, which was today's topic. And then I want to take up yesterday's comment on energy efficiency.

I felt that the report did a really good job in identifying some of the recent achievements and the continued barriers and challenges to a more functional power system, which is responsive to ratepayers' needs for efficiency, affordability, reliability, security,

sustainability and less pollution.

I did feel that the report could be even better with some minor changes in the way it's put together, because the chapters and subchapters are a little scattered around right now. And I wondered if you would consider putting them into more of the loading order, you'd have two chapters on overall policy, electricity needs and procurement, and the water and energy strategies.

And then start with conservation and efficiency and demand response; move on through renewables, distributed generation, combined heat and power. And then do the natural gas, coal and nuclear together. It seems like that would -- it was a little odd to see nuclear and coal in the energy efficiency chapter. And then end up with transmission and the border energy concerns.

Also the climate change chapter, it seems to me it could be a good closing chapter. It also could be an introductory chapter, since that has so much to do with what's driving a lot of the changes right now.

I had specific comments which I'll put into my written comments. The very beginning of the electricity procurement chapter, I just want

to pick this one piece out. Currently it says, following a period of flat growth to slow growth on the heels of the 2000/2001 crisis, California's demand is now growing fueled by population growth and a rebounding economy.

I would tweak that a little bit. The public's extraordinary conservation response during the energy crisis created a period of flat to slow growth on the heels of the 2000/2001 crisis. Following the energy crisis and the September 11th attacks, Californians got the message from state and national government that conservation was not cool. They were encouraged to increase consumption of all kinds.

California's demand is now growing fueled by higher temperatures caused by climate change. The elimination of Flex-Your-Power conservation messages -- I'd like to remind you that Flex-Your-Power, the state program, was taken over by Southern California Edison. The CPUC granted them control over that program. And the CPUC does not allow conservation messages. So they cut the, you know, I feel, most important part of that program out. And I think that had a large effect on the increased demand.

Also, the report discusses that there was less than expected population growth. And so I'm not sure how much increased demand there was there. also, not clear on how the economic issues impact, because my understanding is that the average Californian has less money to spend today, partly because of high energy prices, than they did in the 1990s before the dot.com crash.

My comments on energy efficiency, I came before you a few months ago, discussed the original energy efficiency report. And I do note that it's kind of a thin chapter if we're talking about energy efficiency being the most -- the top of the loading order. I'd like to see it get a little bit more attention.

And also I think that the Energy Commission has an unusual position in relation to the CPUC on energy efficiency issues because the staff is actually directly coordinating on the programs at the CPUC and on the new rules for measurement.

There's a really important statement early in the chapter that says the IOU planners need to be able to confidently account for energy efficiency savings in their procurement planning

processes and decisions. That is the key sentence that I would just like to see carried through the chapter.

There's a good discussion of the changes in the measurement system; there's a new measurement system that's being developed by Energy Commission and CPU Staff. However, I believe it ought to mention the problems with the old system had to do with the fact that the utilities were in charge of all aspects of measurement for their own programs, which resulted in a lack of credibility for that measurement.

The report endorses real savings; but then it says that the utilities are meeting their targets. Well, currently they're only meeting their targets if you allow them to measure the programs the way they have been measuring them, which includes overstating compact fluorescents by one study says up to 400 percent.

And there are other overstatements in the current projections of energy savings for the current programs. If those were corrected, the current utility programs would not meet their targets.

In 2006 to 2008 similarly the programs

are not able to meet the targets that were set by the CPUC. There has been an interesting group of changes made by the Commission since January in how they are counting energy savings in the next three years.

One of them recently allowed the utilities to claim credit for codes and standards work, which the last I heard was primarily done by your staff. So, I don't see why the Energy Commission should be considered an extension of the utilities to help them meet their targets.

And this is not just a theoretical question of who gets the credit, it also has to do with a large amount of money. Because the PUC has announced the intention of allowing the utilities to collect incentives, shareholders incentives for these programs in order to bribe the utilities to do better energy efficiency.

And so if they do not meet their targets they would only get incentives if they were allowed, as they are being allowed, to claim the codes and standards work.

Now, if we take a look at what they have been getting for incentives, there is a decision on the able pending at the CPUC right now that

settles all the claims for energy efficiency incentives from 1994 to 2001. They would be receiving approximately a half a billion dollars on about $1.5 billion worth of programs. Now that's a pretty nice return on investment, I would think, especially since it's not utility money, it's ratepayer money.

No such incentives are needed, of course, for nonutility program energy efficiency providers. They have just been doing programs for four years without incentives, and would really like to continue. However, as the report says, the CPUC has required a competitively bid system for 20 percent of the portfolio. However, the report does not mention that that competition is being run by the utilities. So I would say that gives a new meaning to the word competitive bidding, having a competitor in charge of the bidding on the program.

Women's Energy Matters at your last hearing proposed a solution for the utility bias in these selection of third-party programs, which would be a standard offer program. They currently do a standard offer for large commercial programs. We would like to see them do a standard offer also

for residential programs. This would not be difficult to implement.

There is a very successful system in Texas that is providing 40 percent more energy efficiency per dollar with a standard offer system. Much simpler on the administrative end. Want to point out that administrative costs by the utilities on energy efficiency are running as high as 50 percent still, even though the CPUC tries to bring them down.

Going back to the original statement, IOU planners need to be able to confidently plan for energy efficiency savings in their procurement planning processes and decisions. This is the area that I think needs the most work, because right now the PUC is claiming that everyone gets benefits from energy efficiency programs because they reduce the need for as much supply side resources. But that's actually not yet happening. And there are a couple of reasons for that.

One is, as we know, that the peak is what drives the additional need for resources, the supply side resources. And the utilities have failed to adequately address that peak in their programs. There's a big fight about it now in the

CPUC proceedings, about how much or how little peak savings are going to be done. This is mentioned in the report, which I appreciate.

PRESIDING MEMBER GEESMAN: I take it you disagree with some of the statements made yesterday as to that problem having been resolved in the last two weeks?

MS. GEORGE: Well, the question of whether it's been resolved in the last two weeks is something I can't really speak to. I do have one quote from a ruling on the 4th, which I'll read you: Joint Staff has not yet developed the resource planning component of the integrated EMNV cycle, that's measurement cycle, to feed the measurement results into the Commission's procurement planning process and the California Energy Commission's Integrated Energy Policy Report.

One of the problems is that they don't have a very good way of measuring peak load. There's complications in that area, and it's been a very vague kind of a measurement that's been done in the past.

So obviously the metering would make a difference. Some of the types of things that the

last speaker was mentioning could help a great deal.

But we're just at the very beginning of paying attention to the peak load, even though there's obvious things that you could do. Which is certainly number one, as TURN says, is to increase your space cooling, efficient space cooling rebates, which the utilities have not been doing.

The other thing that I would want to point out is essential if you're going to be looking at substituting supply side resources, energy efficiency for supply side resources is you've got to look at the location of the energy efficiency.

Now, energy efficiency, each measure is like a mini power plant or an anti power plant. it's producing megawatts that cannot be transmitted or stored. They are located where they're located and that's it.

Now, that actually has a tremendous advantage. If you're looking at a distribution system or a transmission system from a resource planning point of view, when the IOU looks at it, or when the utility resource people are looking at

their need for increased resources, they look at it as a, you know, on the basis of substation line congestion, you know, between substations.

So, that makes it very clear where there's a need for energy efficiency or distributed generation. Right there. It's just as clear as day. All the models will show you that.

And you could do a tremendous amount with energy efficiency if you targeted it at a particular area. Currently there is no information whatsoever about where the work takes place.

Now, that's not because the utilities don't have it. Of course, they have it. They know where they sent their people. And that information is available to them. They do not want to give that information out. And I question why is that.

Partly I believe it's that the utilities have used energy efficiency to reward some of their best customers. And it's also certainly possible that they are looking to get the most from both sides of the system.

There's an argument that, you know, the

reason for incentives, as Mr. Cavanaugh said yesterday, that, you know, utilities have a reason to do energy efficiency now. Well, they do, but they also have a reason not to do energy efficiency, and the fact is that with the system set up as it is today they can do both. They can put together massive energy efficiency budgets and then do the work in areas where it doesn't matter, where it does not, in fact, reduce the load in the way that would allow us to reduce the cost of supply side resources. So, you know, they get it coming or going, you know, in that manner.

And that's what I -- I would like to see the Energy Commission looking at those issues, because as my consultant said, you can do it all with energy efficiency. There is an immense amount of potential for energy efficiency, which has been, I believe, under-counted in past years in the utility-sponsored studies.

But the climate change scientists are telling us we need 70 percent reductions in our emissions. We can get that if we are using energy efficiency in the way that it needs to be used.

So I encourage the Energy Commission to push the envelope with the CPUC on that issue

particularly.

Thanks.

PRESIDING MEMBER GEESMAN: Thank you very much. And, again, thank you for deferring your remarks to today.

MS. GEORGE: You're welcome.

PRESIDING MEMBER GEESMAN: Okay, Kevin, why don't we then go to the staff presentation.

DR. KENNEDY: Okay, thank you, Commissioner Geesman.

My name is Kevin Kennedy and I'm the Staff Program Manager for the 2005 Integrated Energy Policy Report proceeding.

I want to welcome everyone here and everyone listening on the phone or the webcast. I do understand that we had a small problem getting the webcast up and running first thing this morning. If anyone's on the phone because of that I do believe we have the webcast working now.

The agenda for today, and actually as I look at what I have on the screen I realize I missed a piece of it. First, I'm going to give a quick overview of the two draft Energy Report chapters we're considering today. Chapter 3, the electricity needs and procurement policies. We'll

also touch on chapter 5, transmission challenges. I'm suspecting that there will be relatively little comment on that since we did have a separate hearing on the strategic transmission investment plan two weeks ago. But we're open to comments on the transmission chapter or its interaction with the strategic plan.

What I failed to put on this but is on the written agenda is that Lynn Marshall will be doing a short overview, as well, of the revised staff demand forecast.

As I believe most of you are aware, following Committee direction after hearings this summer on the initial staff electricity demand forecast, staff prepared a revised version. That was published late last month, and so we'll have a quick overview of the results of the revised staff forecast.

Then we'll open the floor to comments on these topics. As we've pointed out at various points, written comments are due on October 14th.

I would like to point out that we are having a transcript made of all of these hearings, and point out two things. One, it's extremely useful for the court reporter if you come up to

speak if you have a business card, to leave him a business card so he can get down your name correctly and all of that.

We're also working to get the transcripts expedited. I'm not sure how far in advance of October 14th we'll have the transcripts up, but we're trying to get them posted to the web at least a day, maybe two, ahead of that. So if you want to take a look at the transcripts as you're finalizing your comments, I'm hoping that we'll be able to pull that off.

This is one of a continuing series of hearings on the Committee draft documents. We're sort of doing a double-header today, with the electricity needs and procurement policies and transmission this morning. Starting at 1:00, or perhaps later, depending on how the morning goes, we'll be taking on natural gas.

The schedule from here, one thing that's not included in this listing of the schedule is that we are still working on the Committee draft of the transmittal report to the Public Utilities Commission. We're hoping to publish that sometime in about a week or so, probably either at the very end of next week, or early the following week.

We're also in the process of scheduling a hearing specifically for the transmittal report that will be at the end of October or the first week of November. So, keep your eye out for both that document and that hearing.

Then in early November we will be publishing the final Committee versions of the Energy Report and the transmission strategic plan and the transmittal report following the hearing that we hold on the draft.

We're looking to adopt all three of the reports at the November 16th business meeting. And then package it all up and send it off to the Governor and Legislature in early December.

MR. KELLY: Real quickly, Kevin, could you explain how the transmittal report is different from the Energy Report?

PRESIDING MEMBER GEESMAN: I wanted to jump in there, actually, when he said that and offer my cut at an editorial comment.

The transmittal report is not expected or intended to be a policy document. Instead it is a documentation of the record that we've relied upon in developing the policy statements in the Energy Report. It will be a quantitatively

oriented report. It will have quite a bit of detail on demand forecasts and projected supply requirements.

And I know that there are parties that will want to scrub through that fairly carefully to make certain that it is consistent with the policy recommendations in the Energy Report. And to address it as if it were a policy document.

So, to some extent, it's a second bite at the apple for the various participants in our process. We will hold a separate public hearing on it before it comes to the full Commission on November 16th for adoption, along with the Energy Report and the strategic transmission investment plan.

MR. KELLY: So it sounds like it's kind of the technical appendices?

PRESIDING MEMBER GEESMAN: I think our lawyer is still struggling with how to properly describe it. The Public Utilities Commission has requested, in the two ACRs in their procurement proceeding, that we provide them with a transmittal report.

And I think as far as the lawyer has been willing to go is to recite provisions of

those two ACRs.

MR. KELLY: Thank you.

DR. KENNEDY: Okay, thank you for -- that's actually a very useful point of clarification.

In terms of the Energy Report proceeding overall, the purpose of the Integrated Energy Policy Report is to help develop a statewide integrated energy policy. It's also intended to provide a common information base for agencies in the state that are making decisions related to energy policy. And it's one that we're expected to adopt every two years, with an update in the off years.

In terms of the proceeding this year we've been working closely with a wide variety of federal, state and local agencies. We've held many hearings and workshops. And there's a lot of material in the docket in terms of staff and consultant reports, comments, presentations.

This proceeding would not have been possible without a lot of hard work on the part of staff and consultants here at the Energy Commission, and also the very active participation and cooperation of folks from other agencies, and

many stakeholders. So I want to thank everyone who's been involved in helping create what is a very rich record for the Energy Report proceeding this year.

In terms of the chapters that we're talking about specifically today, the electricity needs and procurement policies. In terms of demand we've been looking at statewide annual electricity consumption; it has increased an average of 2 percent per year over the last two years. Consumption is forecast to continue growing through 2016.

Peak demand is also increasing. We'll be hearing more detail about all of this from Lynn Marshall once I get off the stage.

In terms of supply there have been 22,000 megawatts of new power plants approved since 1998. Seven thousand megawatts of those are stalled because of lack of power purchase agreements so far.

The number of annual new power plant applications that the Energy Commission has received has drastically decreased in recent years. We received a high of 42 in 2001, and we only have received so far five in 2005.

In terms of resource adequacy, California could face low reserve margins and shortages in coming years, particularly in southern California. But effective in June of 2006 the IOUs must meet a year-round planning reserve margin of 15 to 17 percent.

There's currently no mechanism in place to insure the resource adequacy for the publicly owned utilities beyond their own internal mechanisms for assuring their own adequacy.

One of the big issues that has played out over the course of the last year in this proceeding has been the question of confidentiality. The Energy Commission is concerned the confidentiality of IOU data precludes open public resource planning process. And confidentiality of the renewable portfolio standard procurement data hampers the ability to insure that the public funds for above-market RPS costs are appropriately spent.

Some of the key recommendations in this area are to require utility long-term procurement to cover the annual net short, plus an amount to account for the possible retirement and replacement by 2012 of an identified list of aging

power plants.

Also recommending that the Legislature should adopt resource adequacy requirements for all load-serving entities in the state. The Energy Commission plans to participate in the PUC rulemaking process to revise their regulations governing disclosure of records.

I would also point out that we are going to be fairly shortly opening up a rulemaking here at the Energy Commission on data collection and confidentiality, looking towards the 2007 IEPR cycle.

We also recommend that the CPUC should not rely on confidential procurement review groups as part of their procurement approval process.

In terms of transmission challenges, congestion-related and reliability services cost Californians about $1 billion last year. California lacks currently an integrated transmission planning and permitting process that would include long-term corridor planning. California needs major transmission infrastructure to interconnect with remote renewable resources.

Some of the key recommendations from the report include establishing a comprehensive

statewide transmission planning process. Transferring siting functions for transmission lines from the Public Utilities Commission to the Energy Commission. Giving the Energy Commission authority to establish a corridor identification process, and to designate corridors.

To identify cost effective projects that increase the ability to transfer electricity between the ISO-controlled areas and other California-controlled areas. And also to take advantage of the complimentary utility systems in California and the Pacific Northwest.

The report includes recommendations in favor of a number of specific transmission projects, including the Palo Verde-Devers 2 project, SDG&E's Sunrise Powerlink project, the Tehachapi transmission projects, and the Imperial Valley transmission upgrade project.

I do want to mention, I think I skipped over this at the beginning, that for folks listening in on the webcast, if you decide that you want to make a comment, we do have a call-in number. It's 888-790-1711; the passcode is hearing; and the call leader is Kevin Kennedy.

If you're seeing the slide presentations

on the webcast, I'll be putting a version of this slide up when we finish the staff presentation so that if you decide later you want to call in, you'll have the number available.

And with that I'd like to turn it over to Lynn Marshall.

MS. MARSHALL: Okay, as Kevin said earlier, back in June we presented our draft staff forecast. And at that workshop there was a lot of discussion about the uncertainties that drove the differences between the staff forecast and the forecast submitted to us by IOUs and other LSEs in the state.

So, in response to that, the Committee directed staff to develop a range of forecasts that encompassed the different perspectives put forth on those issues.

Assuming when and if the forecasts we're presenting today are adopted by the Commission, there's a couple of important applications at the PUC parties should be aware of. One is in the transmittal report, which we were discussing earlier. The forecast for the IOU service areas and bundled loads that we've developed and we'll show later will be used specifically in that

transmittal report for our analysis of resource needs in the IOU service areas.

The second application is in the PUC's resource adequacy process. The draft decision on that process, recently put out by the PUC, put forth the position that it is appropriate to use the state's forecast as a reference case. So if that position is upheld in their final decision, it is likely that the adopted CEC forecast would be used to adjust the forecast used by LSEs for resource adequacy compliance, in the event that the sum of the forecasts submitted to us deviate by more than 1 percent from our forecast. So, in effect, we'd be using the CEC forecast as a control total.

How do we develop these forecast ranges. The first major change since June in all of the new forecasts we're presenting today is we incorporated 2004 consumption data; our June forecast was calibrated to the 2004 peak, but only used 2003 recorded consumption data.

In constructing the cases I'll talk about the changes to the major sectors. In the other sectors the only changes are use of new consumption data.

In the industrial sector the discussion at the workshop, many parties felt that our forecast seemed unreasonably high in light of the current market conditions in California. And so we went back and reevaluated some of our modeling assumptions. With this forecast we've started using the county-level value-added projections, both historical and forecast, by economy.com.

So the use of that data now allows us to go back at a planning area level and look at each NEGs group at the historical relationship between energy use and the value-added driver that we're using. So we've now revised our energy efficiency trends to be more consistent with the trends that we've seen historical data.

In the mining sector we did that same analysis and actually what we found is in about the last five years there appears to be increasing energy intensity in that sector that might be driven by higher resource product prices. So we've actually increased the forecast for that sector.

In commercial models, commercial forecasts, the discussion centered around future trends in energy use per square foot. And in the

staff forecast we projected decreasing electricity use per square foot. That's in contrast to recent history, but that reflects the effects of building and appliance standards, of slowing in the growth of office equipment. That businesses aren't adding computers at the same rate that they were in the '80s and '90s. And also that as some of that old equipment is replaced, it's replaced with more efficient equipment.

By contrast, some of the IOUs' forecasts had increasing use per square foot, basically extrapolating, assuming that the recent historical trend was going to continue. So to come up with a range of forecasts in the commercial sector, the Committee directed us to have a high case that had flat to increasing use per square foot. So we did that by removing some of the effects of lighting standards from the high case and by accelerating growth in our miscellaneous and office equipment end uses in the commercial model.

The basecase is essentially the same as the June forecast. And the low case we actually added in more savings from lighting standards.

To construct the residential ranges we varied assumptions about personal income and

persons per household. So in our basecase and in our June forecast we assumed decreasing persons per household at about half the rate of the trend seen in the last decade or so.

We were also incorporating in that a new somewhat higher personal income forecast from economy.com that they put out in June. We're also incorporating some new population projections that DOF has re-estimated, persons per household for 2000 through 2004.

We're using those new data in the high case, but for the high case we assumed that persons per household stayed constant, so that means more households and a somewhat higher total residential energy use.

For the low case we used the same new demographic information, but we're using our old lower personal income.

So results overall. At a statewide level the revised basecase forecast is very similar to what we had in June. We have somewhat higher residential forecasts, but lower industrial. The low case is only about a half a percent lower than our basecase, but our high case, with the higher growth in industrial and

higher commercial demand, ends up being about 3 percent higher by the end of the forecast period.

So in the high case we have increasing use per capita as opposed to the basecase forecast, which is just slightly declining.

On the peak side we end up in our high case with about 2000 more megawatts by the end of the forecast period. And I'll go through some of the sector level results for each of the planning areas. And it shows peak demand per capita again increasing in the high case.

For the PG&E planning area we have a somewhat lower starting point because of low 2004 consumption. But the high case ends up being about 4 percent higher by the end of the forecast. And there's the energy forecasts. You can see the revised basecase is lower than the lime-green line because of a lower starting point.

And similar, the differences in the peak forecast generally mirror differences in the energy forecast. And same per capita consumption trends are generally the same as we saw in the statewide level, increasing in the high case -- increasing use per capita in the high case.

The residential sector, the high case is

only about a half percent higher than our basecase. As I said, we have constant persons per household in the high case, but that means -- and that means more households. But we also have more persons per household, and because we're using the same total income, our basecase personal income per household is actually higher in the basecase. So there's some offsetting effects there.

In the commercial sector we have a lower starting point. 2004 commercial consumption was about 3 percent lower than previously projected. But our high case, with the acceleration of office equipment and removal of the building standards, ends up being 10 percent higher by the end of the forecast period. And this shows the same results in terms of use per square foot, slightly increasing in the high case. And as you can see there, the historical trend, it has been increasing over the last decade or so. Staff-based case, we have decreasing use per square foot.

This is the revised industrial forecast; is now about 4 percent lower compared to June. And this shows the energy intensity trends that we revised downward from about use per value-added

decreasing at 1 percent, now down to about 1.6 percent. Now, that's not as fast as we saw during the technology boom of the late '90s, but the recent data suggests that trend has leveled off. And so the new forecast results are more consistent with recent data and with the trend we saw up until about the mid '90s.

Now, this is showing the disaggregated forecast that I mentioned we would be using in the transmittal report. And to develop this what we did was take our planning area forecast; we have reported sales for each of the LSEs listed here. We applied the sector level growth rates to each individual LSE's sales to come up with an LSE sales forecast.

Then to develop a peak forecast we used our end-use load factors from the planning area. And then we reviewed the peak forecast that that initially produced, and compared that to historical peak loads and load factors for each of those entities. So for some of the entities that are more weather-sensitive, we adjusted their load factors down relative to our planning area forecast.

And then here are the results for

Edison. Again, our basecase is very close to June. The high case is about 3.5 percent higher than our basecase by the end of the forecast. There's the peak forecast, you can see a big shift up from the last historical year from 2004 to 2006. And that reflects the fact that there have been below-average temperatures in Edison's since 1998. So we're at about 1000 megawatt of weather adjustment to account for -- to be more consistent with one and two temperatures.

And this shows the higher per capita consumption driven in the high case by that higher commercial and industrial growth. Residential, again, same results as with the PG&E planning area. Only about .5 percent higher in the high case.

When we incorporated the new data from Department of Finance we do now have, continues to show increasing persons per household. So that's actually higher than what we had in June. And, again, the income per household is higher. So that somewhat offsets the effect of more total households in the high case.

Commercial sector, we have a lower starting point, around 3 or 4 percent lower in

2004. But, again, the high case increases to about 4 percent higher than the basecase. And shows the results in terms of use per square foot. Flat in the high case, and decreasing in our staff basecase.

Industrial sector we have much higher starting point there, 3 or 4 percent. But, again, we've reduced the growth rate. And here's the intensity trends, reduced it to -- decreasing it about 1.6 percent a year. And that is consistent with the historical trend from 1980 to 2004 of about 1.7 percent.

And this shows mining, which is largely TEOR electricity use. Both a higher starting point, and we now have a slight increase in the forecast which seems to be more consistent with the recent historical trend.

PRESIDING MEMBER GEESMAN: Might clarify that TEOR is thermally enhanced oil recovery.

MS. MARSHALL: Yes, thermally enhanced oil recovery. So, it looks like the higher prices for crude oil and natural gas are motivating them to pump a little harder. That's probably an area we ought to do more research on to find out what's really going on.

And again, same methodology to develop the LSE level forecast as I discussed in PG&E, so the difference in growth rates largely reflect differences in customer mix among the different LSEs.

And then finally, we'll go to San Diego. Higher, we have higher consumption in 2004. Our consumption forecast. The high case is about 3 percent higher than the basecase. On the peak side, the difference is greater. We've got a greater increase than on our consumption forecast because we have made an adjustment to our San Diego peak forecast. In all the other areas the peak modeling assumptions are the same.

San Diego commented that the amount of residential load that we attributed to be weather-sensitive seemed inappropriately low. So we've now incorporated a new load shape for the residential sector, and we've also done a weather adjustment to better account for below-average temperatures in 2004. So our new peak forecast is about 200 megawatts, or 2 percent higher -- or 100 megawatts higher.

And same differences in the per capita consumption. And here is the new load factor for

San Diego. So you can see a good bit lower there.

Residential forecast, similar results as in the other planning areas. Only slight differences in the residential case. About 4 percent higher commercial forecast in our high case compared to the base. And slightly increasing use per square foot versus staff's decrease. And, again, here's the revised industrial forecast, lower starting point and lower growth rate.

And, again, for the LSE level forecast for San Diego we simply took our service area forecast and we took the direct access sales and assumed it would grow at about half the rate of the sector forecast to assume that there's some growth with existing direct access customers, and perhaps some returning of customers with return rights.

And we did the same scenarios for all of the other planning areas in our forecast. Won't say too much about them. These are at the end of your handouts are the results for SMUD and LA. Both of them are actually a little higher because of the higher residential forecast, and because of a higher starting point reflected in the 2004

consumption data.

So I will stop there and any questions?

Okay.

PRESIDING MEMBER GEESMAN: Are we ready for blue cards, Kevin?

DR. KENNEDY: Yes, we are.

PRESIDING MEMBER GEESMAN: Okay. I think you are all familiar with the blue card rule. I'll take them in the order in which they've been given me.

Steven Kelly, Independent Energy Producers.

MR. KELLY: Thank you, Commissioners. Steven Kelly with the Independent Energy Producers Association. And I will be providing some written comments on the 14th, so I won't go into a lot of specificity here.

I would say that just for the most part, almost entirely agree with the Commission's Staff with the recommendations that are included in this report.

So, what I wanted to do was take a few minutes here to talk about something that I think is actually omitted from the report in its entirety. And I wish the report will raise it

when it's completed.

And I want to put this in a little context, but it's kind of the 40,000 foot question, or vision that is kind of, in my view, affecting a lot of the facts that you've discovered in your report, and some of the recommendations.

And to put this in context, when the Public Utilities Commission adopted their long-term procurement plan, from my perspective in the issue of electricity and procurement they really had two fundamental findings, one of which was there was going to be an open and transparent competitive market; and the second was that there was going to be this so-called hybrid market structure, which was somewhat undefined, but allowed the utilities to participate in that competitive environment under the auspices of some openness and transparency.

Your report finds two fundamental facts. One is that there's a lack of investment in generation and transmission both. And two, there's a lack of transparency and openness in the procurement process in California. And I think they're related.

The key question in my mind is why is that occurring. And from a structural perspective your report goes into a lot of specifics and recommendations about how to fix some of this stuff. But I think there's a bigger issue that is at the 40,000 foot level kind of a structural question that needs to be raised by you in your report.

Why is it that there's a lack of investment in generation and transmission. And why is it there's a lack of transparency and openness in the competitive processes that are being implemented today.

One rationale that I've heard is that the lack of investment is a function of the uncertainty about load from the load-serving entities. And I've evaluated that and thought about that, but come to the conclusion that that argument is only applied in the context where there are IPP projects being bid into open competitive solicitations.

It has never arisen in the context of the IOU projects. All of those have gone forward unimpeded by that argument in applications outside of competitive procurement.

So I don't think that the question about what you're serving for load is really the underlying reason about why we're getting a lack of investment, particularly from the private sector, the non-IOU investment sector. I think it's a lack of opportunity.

The second rationale, and this is one that I actually adhere to, and I hope the Commission will look at, is that it's actually the nature of the hybrid market structure that has been adopted by the PUC that is an impediment. It's an impediment to actually achieving an open, transparent, competitive environment.

Rather than using the open, transparent, competitive market as a means to make the hybrid market structure work, I think the alternative is occurring that the hybrid structure is an impediment to achieving openness and transparency.

And I think this is the big elephant in the back of the room that nobody's dealing with, and the Commission's report, the IEPR, doesn't really, I think, tackle this at least straight on.

The fact of the matter is the IOUs have tremendous financial interest in the what, where and when of investment in both transmission and

generation in California, on both sides. Not only as load-serving entities, but as investment entities.

And I'll just note the history that most of the generation, particularly the nonrenewable generation that has been moved forward in California today is essentially IOU projects that have come through outside of an all-source solicitation, through specific applications that they've fostered at the Commission.

The renewable stuff is going -- and is the function of a pretty competitive marketplace. But when I think about why that's occurring, as opposed to the nonrenewable stuff, I have an inkling that it's because it's kind of esoteric technologies, other than the Stirling technology that was just approved in the last couple months, or thought of in the last couple months, most of it tends to be relatively small. And I just think that there's not a lot of interest there from IOUs from an investment perspective.

So that brings me to the question what would I like you to do, or as part of this IEPR. And I think you should address the application and relevancy of the hybrid market structure for

California.

And in that there are a couple key questions. Can we achieve an open, transparent, competitive procurement process as articulated by the PUC, the Energy Action Plan and this Commission, within that structure. If so, what conditions are necessary and sufficient to make that happen. How do we make it work.

The Commission has articulated, the PUC has articulated the role of an independent evaluator. But IEP and others have filed motions repeatedly at the Public Utilities Commission asking how is this entity going to work with this context. And the answer is there's been a vacuum. Or this is not the right place to raise the question.

This Commission has raised the question in this report and yesterday in the hearings about the role of the PRG. How does that work, and what's the function of that. I, for one, do not believe the PRG is an indifferent entity in the selection of resources. I think they have actually an indirect or direct financial interest in the selection process. And that's affecting the progress that we're making in investment in

generation and transmission.

Secondly, I think perhaps you need to look at what is the option of bilateral contracting and how does that work, and is it working as planned or envisioned by the PUC. This is one of the options that the Commission laid up for procurement. It was going to be open, all-source solicitations that created the condition that might allow for bilateral contracting with certain conditions over it.

But so far, at least, it seems that most of the projects that have actually gone through the Commission's processes have come through kind of what I'll call a bilateral kind of contracting nature, mostly through applications by the utilities outside of an all-source solicitation.

And I'm wondering whether that option is helping or hindering achievement of a truly open, transparent, competitive procurement process. And I'd ask this Commission to investigate that issue.

If it is helping, how is it doing that. If it's not helping, what -- or if it is helping, under what conditions is it working. And if it's not, what should we do about it.

I personally think these are big issues

that until we resolve them we're not going to get to the fundamentals, or answer the fundamental question of why there's a lack of investment in transmission and generation.

And as I indicated earlier, I think it's the huge elephant in the room. And I think it would be very helpful if this Commission would tackle that directly in terms of a query of, and ask the questions and respond to them and put them out there for public debate.

You have done a very good job of raising the question of transparency and openness and I applaud you for that. We fully support you on that. And that is obviously a critical component of making this market structure work.

But I'm wondering whether we can't achieve that goal because of this hybrid market structure or not. And it's a rather academic question that I query to you. I understand that. But I think it's fundamental to where California is today and where it's likely to go over the next couple years from an investment perspective.

The private sector is ready to invest in California. I think there's no doubt, based on the results of some of the procurement,

particularly in the renewable sector, that have gone out.

As you properly pointed out, the problem is the lack of contracts to get that investment moving through the pipeline and get the steel in the ground. And I, for one, think that we need to deal with those fundamental issues before we can really be comfortable that we're going to get the investment we need in a timely manner.

So, I pose that for you now. Leave that as my broad comments, and I will be commenting more specifically on the report next Friday. But if you have any questions I'd be happy to answer them.

PRESIDING MEMBER GEESMAN: Well, I would thank you for some very provocative comments.

MR. KELLY: Thanks.

PRESIDING MEMBER GEESMAN: The next card is Greg Blue, Dynegy.

MR. BLUE: I'll do it over here if that's okay. Can everybody hear me?

Good morning, my name is Greg Blue. I'm with Dynegy, but here today on behalf of West Coast Power, commenting today on chapter 3. But I want to briefly respond to the demand presentation

we saw just recently.

I haven't studied all the details behind them, but to me almost every graph goes up, okay. And the other problem is our fleet of aging power plants is another year older. And as the Apollo 13 astronaut said to Mission Control, Houston, we have a problem.

What I want to do today basically is talk about some highlights because this report is a good step forward. I want to talk about, in our opinion, some of the highlights of the report. Also want to talk a little bit about a couple of the oversights int he report. And then some of our views on the current market conditions, as well as some report recommendations.

First of all, also as I read this report I looked back in the list of participating entities, and I always like to look for either my name or my company's name in there. And didn't see our name in there. Just to remind everybody, we did give oral testimony on July 7th and it is posted on the CEC's website. So we are a participant and have been a participant for a couple of years in this IEPR process.

We think that this process is gaining

more importance as the energy policy tool of California. In fact, we feel it's so important that I gave up my tickets to see Tiger Woods today in San Francisco at the golf tournament to come here. Just kidding.

But, anyway, the reason I put this up here, this is what we basically recommended in the July 7th workshop. And I'm going to talk about some of these as we go through here because in the last three months there's a lot of activity that's gone on that really has affected some of this. Some positive and some not so positive.

Resource adequacy requirements with penalties for noncompliance. Tradeable capacity market. Everybody knows how we feel about that. Long-term procurement from LSEs. The FERC-mandated must-offer should be lifted. Remove uncertainty over core and noncore market structure. And then, of course, my favorite, state support needed to implement incentives for repowering at existing sites. And just keep those in mind as we kind of go through some of this.

Some of the highlights from the Committee draft report. Assessment of electricity supply and demand reinforces a conclusion that

maintaining adequate electricity reserves will be difficult over the next few years.

California must address its long-term electricity needs by bringing new generation online. Lack of available long-term power contracts has stalled construction for more than 7000 megawatts of plants already permitted. Has sharply curtailed the amount of capacity seeking new permits.

Unfortunately, the state has only made minimal progress in implementing many of the previous IEPR recommendations and California's economic prospects are suffering as a result.

The state must increase its effort and take immediate action to address problems in the energy sectors to meet the state's policy goal of insuring adequate, affordable and reliable energy.

First of all, i would like to thank the staff who wrote this report for basically helping me write my presentation, because all these points are taken directly out of the report, itself. Could have been given by me, but in fact the staff, these are direct quotes right out of the report.

And the reason I call them highlights,

they're not really highlights for the State of California, because it kind of -- there's some things in here that aren't really good for California. But it's highlights because this is exactly the kind of messages that we've been telling policymakers for the last two years. So I want to thank the staff for helping me write my report.

And, again, one more page of some highlights. Again from the report. IOU procurement focuses primarily upon near- and mid-term contracts which perpetuate reliance upon the existing fleet of aging power plants. That's what's happening today.

The Energy Commission, at least the point has been reached where long-term procurement must move forward expeditiously. We wholeheartedly concur with that. Especially after seeing the demand forecasts that we saw this morning.

Contingent short-term procurement for local area reliability prolongs the reliance on aging units that could otherwise be economically repowered through longer term arrangements providing similar grid services at a more

competitive price.

Some aging plants are critical to address local reliability concerns. The state would be better off served by repowering those that are locationally critical to the grid. Again, I want to thank the staff again for helping me write my report, because again, these are right out of the report. And should sound familiar to many of you from the things that I've been saying over the years.

There were, however, a couple of oversights. And by the way, we will be providing written comments on the 14th which will have more detail on some of this. And we may even actually comment on another chapter or two besides chapter 3, but today I'm just talking about chapter 3.

In our opinion there are some oversights in this, and it kind of goes back to what we heard about in the very first presentation, was how -- what we need to be doing is integrating energy policy in California. We need to be taking what the CEC is doing, we need to be taking what the PUC is doing and we need to be integrating those.

One of the things that we didn't see in the report, and if it is there somebody can point

me out, I may have missed it, but no discussion on how to integrate the CEC's multiyear focus, I'll call it, which are the studies and the recommendations, into the one-year resource adequacy process and the procurement policies of the LSEs.

And somehow getting some longer term resource adequacy requirements, we think, is real critical. And any support from the Energy Commission on that, I think would be -- would kind of actually support the findings of this report, which basically are identifying them. We need longer term focus in California.

We didn't see any -- no support for the development of a capacity market as the logical and necessary next step for the reform of California's electricity market. I looked in there pretty hard; I didn't see really a lot of, any kind of discussion on capacity markets as being important. I know all of you up there agree with that statement; just didn't see anything in the report on that.

There was an assumption in the report, as well, which we think is wrong. That maintaining many of the older plants on life-

support at low capacity factors have prevented the construction of more efficient plants that should operate at higher capacity factors. We believe that's a wrong assumption.

You know, the reason that -- it's not these older plants that are preventing new plants from being built. It's the lack of contracts that we've heard Steven Kelly talk about just awhile ago. And others have talked about it.

Did not see any --

PRESIDING MEMBER GEESMAN: Greg, wouldn't the utilities tell us it's the older plants that create the lack of urgency about long-term contracts? I mean it seems to me that's a circular argument.

MR. BLUE: It is, but at some point the equipment only lasts so long. I mean the plants can run -- and I'm going to talk about it a little bit further, but a plant can run for multiple years, but at some point it just gets too old, ala Long Beach.

No support for lifting FERC-mandated must-offer with implementation of RMR. We think that's -- one of the reasons we think this is important, and I'm going to get to some of these

in a minute, but a lot of these policies as we keep going along are really pushing things towards the shorter term contracts, versus if you eliminate some of these things it will actually accelerate, we think, longer term procurement; that start happening.

We need additional discussion of local area reliability procurement requirements. The PUC has deferred on that for a year or so, but the report seems to infer that transmission upgrades can solve these problems. And while it can solve some of the problems, and in fact, RMRs can solve some of the problems, we're trying to get away from RMRs. But in reality it cannot be totally solved by transmission upgrades an RMRs.

Just look at the ISO study our local area requirement needs for the Edison/LA basin, they're going out for RMR next year of like 750 megawatts. And the local area requirement is about 4000 megawatts. So we have to deal with that issue. And we believe there should be some discussion in this report on that issue.

Lastly, the recommendation for procurement policies that would deal with retirement or repowering of a group of aging power

plants needs more discussion. While we certainly think there needs to be a policy on retirements and/or repowerings, we've been saying that for awhile, we think it needs more discussion than just an appendix, one paragraph in here that says we should do something by 2012.

Yeah, we agree something needs to be done. Whether it's 2012 or what that is, we think needs to be more discussion on that. And maybe that's a potentially, you know, I hate to keep saying next year, but potentially a topic for next year.

I understand a lot of these things are late in the game to be included in the final report, but these are certainly some ideas.

Lastly, which is not on here, is another oversight, which I'm going to give you a recommendation for. At the end of chapter 3 on page 53 and 54, the grand finale of the whole chapter is that the Energy Commission should make three recommendations. And, in fact, there's only two on there. There's a missing third bullet on what that third recommendation is.

So, I've actually -- I have one for you today. Just to help you out. And it's actually,

I think, fits in with the theme of this report. This recommendation says the Energy Commission should work with the CPUC to incorporate a multiyear or longer term focus on resource adequacy requirements for all LSEs. And I think that's a legitimate issue that the CEC could comment on and start working towards.

And basically, as far as the current state of affairs for California I kind of liken it to what I call the one-step-forward, two-steps-back California energy policy. Again, this report is a step forward. I think there's a lot of positive things out there. However, the current situation is the only contracts that are being out there right now being let are RMR contracts, one-year contracts, short-term bilateral contracts with existing generation.

Now, I do realize that there is -- this is currently. There is a PG&E RFO for longer term contracts. And, in fact, the next bullet, no new generation is starting construction. There probably -- I need to caveat that. I kind of put this together last night, but in San Diego Gas and Electric territory they are building plants down there. San Diego did decide two years ago they

weren't going to wait for California politicians or policymakers. They decided to go ahead and start taking care of their needs. And so they are actually building some plants down there. And they're moving ahead.

The PUC's long awaited resource adequacy proposed decision, I'm not sure if that's a step forward or two steps back in some ways. It's really positive, but what it does it defers a lot of issues. And these issues are the issues that are driving people to the short-term procurement right now. It defers replacement of noncompensatory must-offer. It defers local area reliability procurement.

The initial sanctions for noncompliance are, we think, inadequate to actually have any meaning. It also defers discussion, or it talks about the capacity process, capacity market process as a whole another proceeding, which in my -- anytime you have a new proceeding it's deferring it from actually happening. Because that's going to take another year or so to get done. So, in some ways it's deferring issues that are really driving the utilities and LSEs back to shorter term purchases.

The other thing that's happened, of course Edison has filed a motion to withdraw their RFO for new generation. The ISO, a couple weeks ago, delisted approximately 960 megawatts for the 2006 RMR of southern California.

And then when we did have a whitepaper on capacity markets from the PUC that everybody seemed to be getting behind, then the ISO comes out and files what's been described to me as an energy-only alternative proposal, which is potentially a step back. I mean I'm just not sure we can get there in time. If they were here they can correct me. Maybe it's not an energy-only proposal, but that's how it's been described to me.

So this is kind of what's going on in the state of California. So, we're sort of making progress, but we're sort of not.

And, of course, this is from the September 12th presentation that I guess many of you were at, the Joint Energy Agencies meeting. This is the 2006, kind of our first look at next summer. And this is from, I guess it's a joint CEC/CPUC presentation.

I was looking at next year, and really

the reason I brought this up was to point out that while in some respects some people have said, gee, we're looking better, look at that, man. We've got, you know, expected operating reserves of, you know, only down to 14 percent in September.

Didn't you look at the adverse scenarios. And then when you get to the adverse scenario, the one-in-ten and so forth, and we, by the way, glad we got through this year with some cool weather. Last year was fairly cool. I'm not sure, one of these years we're going to have a hot year. And you may end up with something like this.

But the thing that really stuck out to me on this slide was line 21, existing generation without capacity contracts. Now, that was at that time. And I don't know if anybody has signed any capacity contracts between now and then. Nonetheless, this line 21 is included in line number 1 as part of the existing generation.

And we can run the numbers pretty quickly on some of these existing generation that without a capacity contract of any kind you cannot recover your full cost. Just based on the -- just looking at historical prices with all the

mitigation, with all the -- with everything we've got in California, these older plants just cost more to operate. And you cannot recover all your costs absent an RMR contract or a capacity contract.

So that's just highlighting again where we are in California today. Or this is actually as of September 12th.

Lastly, we have some recommendations for the report which we'll also be submitting on the 14th. Again, talking about the need for integrating the multiyear focus into the PUC's resource adequacy requirements, we think that's important. We think this report could really help with that.

The other issue that we bring up here is that we are supporting an expedited PUC proceeding to address the need for and construction of new generation to support grid reliability. And that's in direct response to the issues that Edison has been raising in their RFO about, okay, if everybody is -- you know, who is going to build the next generation to support the grid.

You know, San Diego is -- they're resource adequate. Edison's resource adequate.

LADWP is resource adequate. You know, everybody else seems to be resource adequate. Somebody's bluffing, you know, playing a game of poker down there. Somebody's short according to all the forecasts, all the forecasts.

We just, that's one of the things we really need to do is to figure out where are the missing megawatts. That's not my quote; that's what other people have said. Where are the missing megawatts.

But, as part of that proceeding we think that the scope of that proceeding must allow the LSEs to provide testimony, so that means all LSEs, on whether the resource adequacy commitments in the form of long-term PPAs benefit all customers in the zones. And if so, whether the costs should be allocated or not.

We think that's a legitimate issue. It's not, you know, this is kind of something that's come up during the Edison RFO. But we believe it is a legitimate issue; it needs to be looked at. This Commission needs to start, as well, looking at it and perhaps integrating in with the PUC on giving your thoughts on all this.

We believe, of course, kind of repeating

on some of our oversights, the report should state that the design and implementation of a durable instate capacity market suitable for the California environment must begin now, must be completed as expeditiously as possible.

We think that the report should advocate for the lifting of the FERC-mandated must offer. And a shorter transition for the use of firm LDs as counting toward resource adequacy requirements. Right now the proposed decision from the PUC allows them to go out to the end of '08. But on a descending, you know, kind of a scaling back each year.

Nonetheless, again, that allows the LSEs to rely on those rather than having to go out and procure steel in the ground, which would hopefully bring some new steel in the ground, new contracts for California.

And lastly, of course, we think that the continued support for repowering with new generation critically located at sites, we appreciate the support of this Commission, certainly recognizes this issue. The Legislature recognized it when they passed AB-1576, the Governor signed it two weeks ago. I guess it was,

or a week and a half ago.

Policymakers are realizing the benefits of this, but we really haven't been able to work that into the resource adequacy requirements and/or procurement policies of LSEs. And I think that this Commission could help moving that ball along, too.

PRESIDING MEMBER GEESMAN: My recollection is that it was favorably mentioned in the PUC's December 2004 procurement decision.

MR. BLUE: Yes, it was. And I remind my utility friends of that often.

PRESIDING MEMBER GEESMAN: Just seems to me, Greg, that, you know, that you characterize it as one-step-forward, two-steps-back. I think I'd characterize it as the inherent limitation of good words. At some point good words don't substitute for signatures on long-term contracts.

MR. BLUE: I couldn't say it better myself.

PRESIDING MEMBER GEESMAN: I thank you for your presentation. I do have a question. I wonder if you would care to comment on the widely reported remarks by Commissioner Kelliher regarding capacity markets versus long-term

contracts?

MR. BLUE: What was the genesis of what he said?

PRESIDING MEMBER GEESMAN: You and I were both at the --

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: -- at the Independent Energy Producers meeting, and Commissioner Kelliher was asked about his belief in the role of capacity markets. And I think, as you indicated, this Commission has supported capacity markets pretty strongly in the past.

He indicated, and was reported in the trade press pretty broadly, as having a preference for long-term contracts as a more reliable means for incenting new investment.

MR. BLUE: Right.

PRESIDING MEMBER GEESMAN: And characterized capacity markets as still somewhat untested --

MR. BLUE: Right.

PRESIDING MEMBER GEESMAN: -- in their ability to bring steel into the ground.

MR. BLUE: Okay. Yeah, our opinion on that, and I believe we've actually stated this in

previous testimony, but our opinion is you really need both.

But right now you can't really start a capacity market when you're in a resource deficit position. Right now we are in a resource deficit position in the next relatively short period of time.

And so because of that we believe that you have to have long-term contracts initially to get enough generation capacity on the ground, so you have sufficient capacity, so that you can start a capacity market.

Once again, I think the preference right now, based on what we're hearing from our lenders and from our board and from our shareholders is that they want a contract. Well, again, you're right. The capacity markets have not had a long track record.

However, we firmly believe that over a period of time is when the banks are going to start getting more familiar with capacity markets, and you may not -- you can get a contract, or at some point in time the banks may start relying on the stream of revenue from a capacity market. That therefore they would be willing to start

lending on that basis.

So, we believe that you still need to have both in the market. That's our opinion.

PRESIDING MEMBER GEESMAN: Thank you very much. Gary Ackerman, Western Power Trading Forum.

MR. ACKERMAN: Commissioners geesman, Boyd and Desmond, good morning. I'm Gary Ackerman, Executive Director of the Western Power Trading Forum, a trade association of 44 entities that trade power across the west.

I'm deeply disturbed by a comment that my friend and golfing partner, Greg Blue, made that he sacrificed tickets to see Tiger Woods to come here and talk to you today. I have no such sacrifice to show you my love and devotion for your process. But I'm here, and so are you.

And today I want to address the Commission not only on a topic that's in chapter 3 of your draft IEPR for 2005, which would have to do with long-term procurement, but how it interplays, as I think you well know, with another chapter in your draft document on emissions and greenhouse gas policy, which is chapter 9.

And the two run into each -- well, they

don't run into each other, they slide into each other. And I think we should discuss that. So before I go down that track a little bit and expand on that point, what I want to do is tell you what the WPTF, Western Power Trading Forum, policies are that we've all agreed upon which we revise from year to year, but as of right now, regarding greenhouse gas and carbon emissions so it will set the stage for what I'm going to say thereafter.

So there are four points that our group has agreed upon. First of all, we believe that the policies for controlling emissions should be handled through legislative mandates rather than CPUC orders.

Second, that market-based solutions should be used to minimize the cost of achieving any greenhouse gas goals.

Number three, since greenhouse gas regulation deals with a global problem, California's specific regulation would be far less effective, I think you'd agree, than international, national or regional regulation.

And finally, that greenhouse gas regulation is more effective if applied across all

industries and sources of emissions.

And as I read your policy and heard you speak on various occasions, we believe that the Commission and the policies, as we have them, are fairly well aligned. But I didn't drive up here today to tell you about the things we agree upon. That's not too interesting, so let's make this interesting, let's talk about the things we might not agree upon too much.

And that has to do by bringing an important resource under long-term contract into California, coal-fired power by wire.

Coal-fired power is necessary for the west and for California consumers. Without significant imports of coal by wire electricity costs would certainly jump up. The variability of electricity prices would increase if it were based more and more on gas and less and less on coal. And grid reliability would certainly be weakened.

All three of these outcomes are strong negatives and cannot be ignored, nor can they be tolerated.

The challenge is finding a way to tap coal resources while reducing the total emissions of greenhouse gases and criteria pollutants.

Our answer to this problem is to allow the use of emission offsets which will enable a market-based approach to achieving the standard or any standard you folks set at minimum cost.

Now, offsets can come from many different sources. Offsets can come from terrestrial sources. Offsets can originate in nonpower sectors such as transportation. And most important, offsets can be traded at a market value. And as I stated at the outset, we support market-based solutions in reaching greenhouse gas goals.

If your draft report and final report could put some more flesh on the bone, as to exactly how a wide range of offsets could be verified and certified, then it would go a long way to developing a robust system that achieves the two goals of lower cost and a cleaner environment.

And unlike dropping the pebble in the pond and the ripples go out from there and they dampen over time, I think where you're at right now with this policy and this discussion is the exact opposite. This is a small ripple. You've introduced the concept, you're discussing it. And

I believe it's important. It's going to grow and grow over time. So I think what you do now in the early stages will have a very strong and long-lasting impact, and be built upon.

Another approach that we would support is evaluating total emissions based on a portfolio of coal and renewable resources that, on average, achieve an emissions level equal to or less than the proposed standard that you folks mentioned, that being the emissions of a combined cycle natural gas turbine.

The renewable power in the mix would have a value, in that coal, on a stand-alone basis, would otherwise be unable to comply with the California standard, even with the best available control technology. So it's easy to imagine that aggregators want to sign long-term contracts with buyers, would bundle coal and renewable resources together into a import portfolio that would have a definite value and that would provide the renewable asset owners a significant revenue stream.

So, we support market mechanisms to achieve emission targets, and we support a system that could certify offsets, and we support

creative bundling of thermal and renewable resources for California power imports.

I want to close with just one comment, or two comments actually, regarding your report. My Board spent considerable time working with me, discussing the comments that I've just shared with you. And the debate has been vigorous; I think it's just going to increase in vigor in the time that we spend on it.

But I thought you might like to know that there was unanimous opinion expressed by the members in my group that the 2005 IEPR report is probably the best document they have seen on a wide range of energy topics and policy options. It is factual; it's to the point.

I would note that one criticism or shortcoming that some folks noted, and I think you should also think about this, is that the draft is silent on some form of tradable capacity instrument and a market to trade that kind of instrument that would support the resource adequacy requirement. That was told to me, and I double-checked by looking in you chapter 3. And, indeed, I couldn't find it.

Let me put it this way: If you find

that comment strange and I find it strange that you would find it strange, then we better talk. Because that is a central point to making what we need here in California work, especially given what we think will be the order coming out of the PUC on resource adequacy and how it will affect the changeover, this transition, which Mr. Blue alluded to, between now and the end of 2008. Got to have a capacity instrument; it's important.

Notwithstanding that, California is well served by this Commission's endeavor, and the agency and staff should be congratulated on its effort. Thank you, that concludes my remarks, unless you have questions.

PRESIDING MEMBER GEESMAN: Thank you, Gary. You are a pretty close student of the way the half-dozen or so different California agencies interact with each other.

In terms of developing the type of climate or greenhouse gas regulatory regime that would clarify the role of offsets, do you really think this Commission should get out in front of the Governor's Climate Action Team, which is due to report in January?

MR. ACKERMAN: Well, January's pretty

close for this Commission, I supposed, to try and do something or craft something that would quote, "get in front of everything else."

But as I said earlier, I think what you're doing now obviously we're paying closer attention to with regard to the role of coal imports, for example, and how it will fill a certain need here in California.

If that's a start, and I see the amplitude of those waves getting larger and larger then I think you don't have to get in front of anybody to do the good things that I think you're capable of doing.

So, you know, agencies come and go, policies come and go, I'm a little bit of a cynic about that. What ultimately happens in the long run will depend not only on what you folks come up with, but also what kind of agreements can be mustered with Oregon, Washington and maybe the other states in the west, which I think is happening on the Governor's team, as well.

So I don't know if I've answered your question. Maybe I have. I think I've indicated you can't jump out ahead, the time is too short. But that doesn't, in my mind, diminish in any way

what you've achieved or attempted to achieve here in your draft report.

PRESIDING MEMBER GEESMAN: And the other topics, tradeable capacity product, resource adequacy requirements, even in this new era of close collaboration between agencies --

MR. ACKERMAN: Love, call it love.

(Laughter.)

PRESIDING MEMBER GEESMAN: I don't want to lessen --

MR. ACKERMAN: Yeah, right. I had to read that one into the record.

(Laughter.)

PRESIDING MEMBER GEESMAN: Even in this new era there is a finite list of things that we can effectively convey to the CPUC. And I think one of the primary motivations of our focus in this report is to try and concentrate attention on the pretty simple message that it's long-term investment, stupid.

I'm fearful that some of these other issues, that we've dealt with in our past reports, and they've certainly come up in our hearings, and we do have a collaborative effort with the CPUC in their resource adequacy proceeding.

I'm fearful that trying to address too many of these shorter term issues contemporaneously with our key message may not be well received by our colleagues in San Francisco.

MR. ACKERMAN: I disagree. I don't think that this one particular issue that I've mentioned to you, the shortcoming, should be put to the side for fear that it is maybe excess baggage on some of the other messages that you put forward.

After all, this is a document that is very broad. It's noted as such. It's appreciated as such. And being silent on something sometimes sends a message that you didn't intend. And I think you've sent that message. It's an incorrect message, --

PRESIDING MEMBER GEESMAN: That's fair.

MR. ACKERMAN: -- and I want you to correct it.

PRESIDING MEMBER GEESMAN: That's a fair comment.

ASSOCIATE MEMBER BOYD: I want to expand on this same dialogue a little bit. I had the question, I'm still going to ask it, even after this last discussion.

Commissioner Geesman asked Greg Blue about the capacity market concept vis-a-vis long-term contracts. And you've been talking around that just now.

But I'd like to hear your answer to the very same question. Or I'd like to ask if you agree with Greg. He said --

MR. ACKERMAN: No.

ASSOCIATE MEMBER BOYD: -- you got to have the long-term --

MR. ACKERMAN: Well, you're really going to see some dancing around now. Keep in mind that when you have as many members as I do that represent both generators and marketers and load, they're going to look at things quite differently. And they're going to look at, for example, capacity markets as being instrumental for attracting long-term investment. Whereas the marketers in the load, load-serving entities, will say no, it's quite the opposite. It's long-term contracts.

So, I'm faced, as just this is reality, with the fact that there are two answers out there. And I think, and I've characterized this in my private musings, which of course you don't

see very much of, Jim, I know, but in my private musings as we're at the point of the I-don't-know phase in this debate.

And John mentioned Kelliher's comment at the IEP meeting two weeks ago, and it struck me. It struck me very hard that here was somebody who has a sense of where this thing might be going, and he answers the same way: I don't know, I don't know if it's capacity markets that are necessary to have a competitive wholesale market or not.

So, I'm not going to be able to answer your question in a satisfactory manner, as you like, because there are differences of opinion. And I think when you're looking at energy you're going to run into a number of issues where there obviously differences of opinion. This is just one of them.

But I think the important thing to take away is if you think it's capacity markets and nothing else, I'm pretty sure you're wrong. And if you think it's long-term contracts and nothing else, I'm pretty sure you're wrong. Somewhere the answer must lie, the truth must lie. But we haven't found it, nor has any other region in the

country.

ASSOCIATE MEMBER BOYD: I thought you were getting off too easy earlier, so, thank you.

MR. ACKERMAN: Yeah, well, you know, we try.

PRESIDING MEMBER GEESMAN: And I would credit you with publishing your private musings every week.

(Laughter.)

MR. ACKERMAN: Well, that's just a coincidence. Has nothing to do with why I'm here today. Or have an option on tickets to Huddart Park later this afternoon. I have a price in mind, you can talk to me later.

Any other questions?

PRESIDING MEMBER GEESMAN: Thanks, again, Gary.

MR. ACKERMAN: Thank you.

PRESIDING MEMBER GEESMAN: Robb Anderson, San Diego Gas and Electric.

MR. ANDERSON: Good morning; I'm Robb Anderson, Director of Resource Planning for San Diego Gas and Electric. We will be submitting written comments next week, but I just wanted to highlight a few items for you today.

First of all, we thought the report did a very good job on highlighting some of the threats and concerns that we do have in the state. But one of the items that we were looking for that we really don't see in the report is how are we going to trade these off. We're not convinced that we can do all of them all at the same time.

As the Resource Planner right now, I'm already receiving more policy guidance and more comments that I've actually got room in my resource plan to accommodate. So I have to sometimes prioritize these things.

And more guidance from you to the extent we do need to trade off or do some prioritization, letting us know which direction you'd like us to go, we would find helpful. Right now we follow the loading order. That may be the right thing to do. If there's another direction, we'd be interested in hearing it.

In the overall resource chapter the only comment I'd like to make today is we will provide you some written comments. I'll try to make them as modest as I can, but we'd like the report to recognize some of the efforts that certain parties are already taking in this area. I did not script

Greg Blue, although I will thank him for the comments.

And SDG&E has been signing long-term contracts. In fact, about all we've been doing is signing long-term contracts. Those contracts are resulting in 2000 megawatts of new capacity getting built in the state. Some of those projects are already online delivering today. Others are finishing up construction and will be online before the peak of next year. Others will come on then in the next year or two after that.

And I note 2000 is a bit of a dent in the state, but that really represents about 50 percent of San Diego's load. So we have made a significant commitment to long-term contracts to get new capacity built to serve our load.

PRESIDING MEMBER GEESMAN: How have you mustered the courage to do that in the face of uncertainty about who your future customers will be?

MR. ANDERSON: We really looked at it from the standpoint of we need to make sure that reliability is met. And most of our contracting was done in order to get power plants built within our load pocket. And if we didn't step up and do

it we knew it wasn't going to get done.

And the general view that the utility was, in the end, going to get held accountable for the reliability of the system. So we've stepped up --

PRESIDING MEMBER GEESMAN: A traditional utility perspective on public service.

MR. ANDERSON: We've stepped up and done it. We've asked the PUC and have gotten, we think, fairly good assurances that should load leave we will get some stranded cost recovery for those commitments we've made.

PRESIDING MEMBER GEESMAN: And an awareness that if you don't meet those public service obligations your regulator is likely to clobber you.

(Laughter.)

MR. ANDERSON: I think that's --

PRESIDING MEMBER GEESMAN: I wish you had more influence within your trade association.

(Laughter.)

MR. ANDERSON: I'd like to make a few comments on the staff's electric load forecast. The staff has updated it. They took a number of our suggestions from the draft forecast and have

included those in the new forecast. And we are actually now pretty comfortable with the load forecast through about 2008.

Beyond 2008, though, we still have some concerns with the forecast. And I'm not the load forecaster, but let me kind of put in a pretty broad perspective.

If we look at peak load growth per capita in San Diego, during the 1980s it grew at 1 percent a year. During the 1990s it grew at 2 percent a year. During the last couple years it has grown at 3 percent a year.

The staff's forecast right now for '08 through '11 excluding DSM, note the numbers I gave you before are after all the impacts of DSM, has it growing at .2 percent a year. If we roll in DSM, I think the staff's forecast is actually a negative peak load growth per capita.

We're not aware of any fundamental shift that will occur in San Diego that will cause the load to taper off that much in that timeframe.

This is also a time period that I'm very concerned about because the 2010, that timeframe is now the timeframe that we are really focusing on because that's when our DWR contracts start

falling off, we start seeing additional grid reliability issues in that time period. So we think the forecast out in that time period is very critical to get and get it right, and make sure that at this point in time we're not under-estimating load. Because we all know what happens when we do that.

Lastly, on the greenhouse gas proposal. Right now --

PRESIDING MEMBER GEESMAN: Before you get to that, Robb, can I ask that your written comments address those forecast differences in as much detail as you have the time to do in the next week?

MR. ANDERSON: We will.

PRESIDING MEMBER GEESMAN: We'd appreciate that.

MR. ANDERSON: On the greenhouse gas proposal, right now we probably have more questions and concerns than a real answer to you at this point in time. And some of these you've heard from other people, and I'll highlight a few others.

First of all is the issue of peaking versus baseloaded resources. I think you heard

that yesterday. It's a standard that baseload resources may be able to meet. Peaking resources right now cannot. And the majority of what we're going to need in the future are going to be peaking resources.

PRESIDING MEMBER GEESMAN: And that criticism is --

MR. ANDERSON: Right, we need --

PRESIDING MEMBER GEESMAN: -- well taken.

MR. ANDERSON: -- to iron that one out.

Next is by adopting such a standard are we, in essence, creating a greater reliance on natural gas, or at least accepting the reliance we have on natural gas at this point in time. I'm not sure that we've thought that out. If that's the tradeoff we're making, fine. But let's be clear that that's what we're making.

I don't think we can continue to say that our reliance on natural gas is too high if what we've really made is a conscious decision that relying on natural gas is a better thing to do if doing so helps reduce the greenhouse gas impact.

Another point is depending on how we

implement this, we're concerned that it might create incentives once again for parties to go short rather than make long-term investments. And we need to iron out to make sure that we're not implementing this in a way that drives that kind of decisionmaking.

And lastly of all is, as we will put in our written comments, this needs to apply to all. The IOUs are a big part of the mix, but if this is what California needs everyone in California should adopt it.

Thank you very much.

PRESIDING MEMBER GEESMAN: Thank you.

MS. TURNBULL: Good morning, Chairman, Commissioners, Staff. I'm Jane Turnbull; I'm here on behalf of the League of Women Voters of California.

First of all, before I start on my comments for today I would like to take a chance, the opportunity to respond to a question that Commissioner Geesman asked me yesterday with regard to the performance standard for greenhouse gases.

He asked me about would the League support offsets. Certainly offsets makes some

good sense if they are verifiable. I think one of the problems is that in a lot of the work that has been done so far, because offsets come out of very complicated systems, the potential for leakage in those systems is really very great. So only when there is a well-developed cap-and-trade system would offsets really make good sense.

But in terms of what we're all about this morning, both the PUC and the Energy Commission have been proclaiming the critical needs for more power plants and transmission facilities for the past three years. But as the draft report notes, very little progress has been made.

At least the energy efficiency programs administered by the IOUs appear to be in place and evolving effectively. The state's increased dependence on natural gas and the increasing cost of this gas is placing great economic pressure on both businesses and individuals.

More than 60 aging power plants across the state have heat rates of greater than 9500 Btus per kilowatt hour. Overall they are at least 30 percent less efficient than the new combined cycle plants. Yet their owners are able to recoup

the full cost of fuel.

Since it's clear that these owners need an incentive to think seriously about investing in repowering, one possible incentive would be to place a surcharge on the cost of natural gas burned by any and all power plants that have heat rates greater than 800 Btus per kilowatt hour -- 8000 Btus per kilowatt hour.

The League has already presented comments on the strategic transmission plan, but we want to reiterate the vital need to bridge the remaining issues and bring the CPUC and the Energy Commission together to address our serious transmission congestion concerns.

We are pleased that SDG&E has called for public involvement in efforts to site transmission that will bring power into the state from the southwest. We have yet to see any proposal to bring seasonal power into the state from the northwest.

Resource adequacy will not be achieved simply by having the CPUC set up a process, one that attempts to implement a 15 percent planning reserve. Resource adequacy requires that potential investors in new capacity have both the

financial wherewithal and incentives to invest.

For several years the existence of 20,000 megawatts of long-term and expensive DWR contracts has been the reason given for lack of investments. Lately the major reasons that have been offered are continuing limitations on long-term contracts, and the lack of regulatory certainty.

We're not able to judge the relative importance of these reasons. Thus, it appears that it would be prudent to attempt to address both of them. We would like to see a request for offers to provide additional capacity be for contracts of at least ten years. We would also like to have the PUC and the Energy Commission hold a public hearing on why the two Calpine facilities are not entitled to ten-year contracts.

In addition, we would like to see the whole issue of direct access be tabled for at least the next five years. The League does not have a position on direct access. However, we do support efficient, effective and equitable governmental processes. And the recent debates over reinstating direct access have not contributed to regulatory certainty.

We continue to support consistent resource adequacy requirements for all retail sellers in the state. And we also encourage the Commission to do all that is needed to insure that the procurement process be an open, transparent and competitive process.

The draft report presents an important and comprehensive discussion of concerns about the IOUs' demand that resource planning data be kept private. Including the summary comment from the Commission that open public debate about the data, assumptions and alternatives forming the basis of IOU resource planning decisions has been severely truncated -- unquote.

The IOUs' position on confidentiality of data includes all information associated with the application of least-cost/best-fit criteria in the selection of bids and in the details of contracts. Without that information the public cannot have any confidence in the decision process.

This privacy issue may be the most critical one that our state needs to address if there is to be any rationality in the comprehensive integrated planning process.

Before AB-1890 the IOUs did strategic

long-term planning. Now in our so-called hybrid system either the Energy Commission does strategic planning or it doesn't get done. The Energy Commission cannot be effective if it doesn't get good information. It's important to note that the Commission is not looking just to the IOUs for information, but to all load-serving entities that retail at least 200 megawatts of capacity.

The League certainly respects the confidentiality of proprietary information. But we don't support failing to disclose information that is to be used in defining resource planning decisions if that information is directly relevant to the public good.

In light of what has already been said, the League agrees with the draft report that long-term contracts with renewable resources which have no ongoing natural gas price exposure turn the modernization concept into a true hedge against long-term natural gas prices. Renewable resources as the so-called rebuttable presumption for long-term procurement might just come to be a favorite expression around the state.

But one personal further comment that I would like to make is that even though I served as

a member of the National Coal Council for several years in the 1990s, I personally am not optimistic about clean coal technologies in California, or the proposals to sequester carbon dioxide for centuries. I think we should look to focusing on instate capacity rather than out-of-state coal capacity.

Thank you for the opportunity to be here today.

PRESIDING MEMBER GEESMAN: Well, thank you, once again, Jane. I would like to ask you, in terms of your recommendation that debate on direct access be suspended for a period of time, whether you would distinguish community choice aggregation from that.

MS. TURNBULL: We consider community choice aggregation a form of direct access.

PRESIDING MEMBER GEESMAN: So you would suggest that we suspend further consideration of that for the same period of time?

MS. TURNBULL: Well, the League supported AB-117 a couple years ago, --

PRESIDING MEMBER GEESMAN: That was the Migden bill?

MS. TURNBULL: -- but since that time we

have had some reservations. Just because of the regulatory uncertainties that have been multiplying.

So, you know, just the discussion seems to, you know, keep muddying the pie. And just as soon, you know, make sure that we do have the reliability that we're really going to need.

PRESIDING MEMBER GEESMAN: Thank you very much. Al Pak, Sempra Energy Global Enterprises.

MR. PAK: Thank you, Commissioner, good morning. I wanted to start where I left off two years ago with the -- when we were discussing the 2003 IEPR.

(Laughter.)

PRESIDING MEMBER GEESMAN: Now, you've been back several times since then, Al, so --

MR. PAK: Well, I know, but --

PRESIDING MEMBER GEESMAN: -- you're going to have to refresh us if you're going back that far.

MR. PAK: Well, what I wanted to start off by saying was that once again the amount of work and good thinking that has gone into the Integrated Energy Policy Report process, as well

as the Committee draft, are self evident. This is an outstanding piece of work.

And I was part of the discussions that Mr. Ackerman had referenced within the WPTF. That while there were a considerable amount of controversies with respect to some of your recommendations, there was a unanimous agreement that this is a stellar piece of work. And that the Committee and its staff should be recommended for its contribution to the debate about energy policy in the State of California.

With that said, I think this is going to go downhill from there, so --

(Laughter.)

MR. PAK: We very much appreciate the idea that the recommendations related to utility procurement are attempting to strike a balance between achieving and maintaining system reliability, maintaining affordable prices, and mitigating environmental impacts from the energy industry.

In the first instance, we agree that assuring system reliability will require the addition of about 2000 megawatts of new capacity per year through 2016. And that this will permit

the orderly retirement or repowering of existing facilities, the replacement of expiring contracts and enable us to meet demand growth.

Sempra Global also agrees with the recommendation that the utilities should be the ones that should be required to execute long-term agreements for new resources that will meet this requirement.

It is simply the case that under current market conditions the financial certainties offered by utility ratemaking and state support of contracts are necessary, at least from the financial community's standpoint, more reliable than returns that can be achieved through an open market.

We also agree with WPTF that the report needs to go a little further in terms of supporting capacity markets and a tradeable capacity instrument, so that if there is load migration in the future either due to direct access or community choice aggregation, the utilities have an ability to shed the capacity that might otherwise be excess to their bundled customer needs.

You have referenced a comings-and-goings

policy in other portions of the IEPR draft as a method of attempting to deal with potential stranded resources. We think a capacity market would be a better idea. This also would facilitate the year-ahead procurement that nonutility load-serving entities have to go through as a result of the resource adequacy requirements that they will be encountering come this January.

PRESIDING MEMBER GEESMAN: Now, I'm guessing that you're not speaking for the utility today.

MR. PAK: No, --

PRESIDING MEMBER GEESMAN: Am I right?

MR. PAK: -- I'm actually speaking on behalf of my load-serving entity, Sempra Solutions, which --

PRESIDING MEMBER GEESMAN: Okay,

MR. PAK: -- will be required to post up from commitments of firm capacity to the ISO commencing June 1st of 2006. We are entering that market without any assurance that we will have an ability to meet the requirements of the PUC. Nevertheless, we are going to make a good faith effort to do that.

But we think that if the utilities do procurement, to the extent that there is a tradeable instrument available and a market in which to trade those instruments, we might be able to procure, over the long term, from that market.

PRESIDING MEMBER GEESMAN: But if a utility, pursuant to state policy, engaged in long-term procurement, purchased a certain amount of capacity, suffered some load migration through community choice aggregation, as an example, where we have suggested coming-and-going rules that would avoid a stranded asset problem, if I hear you correctly you're suggesting a capacity market as a preferred mechanism to address that stranded asset problem.

And my question to you, in the hypothetical instance that this happened and you were the utility, would you be satisfied with whatever price you could get in such a capacity market?

MR. PAK: I wouldn't want to try to guess at what Mr. Anderson's answer might be.

PRESIDING MEMBER GEESMAN: Oh, I think you could guess.

(Laughter.)

MR. PAK: Actually I would think it would depend on the relative capacity needs of the region as compared to what --

PRESIDING MEMBER GEESMAN: Let's say the utility said the value of the stranded asset is worth a lot more than I can get in tomorrow's capacity market.

MR. PAK: In any event, we think that the market mechanism would be better than some kind of a standard rule. I mean, as it stands now, what the utilities have typically been doing, although you called it courage, there is the CPUC rider in most of the approval processes that any stranded costs would be recovered or assigned to the load that migrated out of the bundled service.

We think that has effects on competition and the viability of the expansion of the direct access market. Obviously San Diego Gas and Electric and the Sempra Global Companies would disagree as to whether that's the appropriate placement of risk. But nevertheless, we do agree with San Diego that you ought to address the risk and how that's resolved.

Going back to the report, Sempra Global also agrees with your recommendation that

transmission corridors should be identified at the earliest possible time and reserved for future use. And further, where necessary, that appropriate ratemaking mechanisms be adopted that would permit the rate recognition of the assets associated with corridors that would be set aside until their use was actually implemented.

We noticed that you had omitted any discussion of the recent action by the Department of Energy and Department of the Interior. In their action they have noticed that they will be preparing a programmatic environmental impact statement for future transmission corridors across federal lands in the west pursuant to the Energy Policy Act of 2005.

We think that there could be a lot of synergies between the Energy Commission and the PUC's activities in the area of identifying future corridors with the DOE/DOI notice. Especially since California is going to remain the largest load sink in the region for the foreseeable future. The terminus of many of these lines is going to be California; and the markets to which they will attempt to reach will be in California.

And we think that coordination here

would be appropriate. It sounds like you're both trying to achieve the same objectives. We encourage you to do that. And to the extent that federal and state cooperation and coordination would improve the process, we would strongly recommend that you take the opportunity to participate in that proceeding.

We agree that California electricity prices are going to remain relatively high across the near term. And that they will increasingly carry price volatility risks associated with perturbations in the natural gas market.

As you know, we are the developers of an LNG terminal in Baja region. That some of the deliveries from that plant will enter the California market. And we agree that the entry of this gas into the California market will have, upon its introduction in about 2008, the effect of a short-term price reduction. But we also agree with the Committee draft's conclusion that gas prices eventually will equilibrate to some higher level against the supply/demand balance that's forecasted in the report.

That has a lot of implications for utility procurement, and I'm going to turn to that

in a moment. Before I get to that I should say that Sempra Global Companies fully accept your recommendation as fact, that utility procurement will be governed and take into account greenhouse gas emission policies in the state. And that that policy will be a part of achieving the Governor's greenhouse gas targets.

We do want to recommend that you provide enough flexibility as to how greenhouse gases are taken into account so that reliability and price goals are not sacrificed in order to meet the greenhouse gas goal as a priority.

Let me say that we fully recognize the importance of reflecting the Governor's objectives in the IEPR and the Energy Action Plan. It's not going to be open to debate, but I don't think there's very much serious debate about the fact that utilization of domestic coal resources can contribute to security benefits, price benefits and risk management advantages in the energy market.

As we have tried to sort through the different policies, and I think Robb Anderson talked about all the different policies he has to juggle in doing his procurement, we've identified

six specifically from the IEPR draft.

One, maintaining retail prices at reasonable levels, and in particular, hedging gas price volatility and gas supply disruptions, whether from a Katrina-style event or a less spectacular pipeline outage.

Two, achieving net reductions in California's contributions to global CO2 emissions.

Three, creating the financial incentives that will result in adding the 2000 megawatts of new capacity per year that are needed. And this, actually we sort of thought this figure would be a little low, depending on how the market restructures itself in response to the CPUC's resource adequacy requirements and the California ISO's MRTU markets.

The fourth goal was providing for the orderly retirement or repowering of aging fossil-fired plants and the replacement of expiring contracts.

Fifth, capturing the values that coal-fired units can bring to the electricity market.

And six, minimizing the exposure to resource stranding that might come from load

migration between load-serving entities.

Now, in terms of balancing these goals we think that you have correctly identified the fact that the rubber meets the road in terms of trying to achieve these, and achieving a balance between these in the long-term procurement plans that are filed by the utilities every two years with the CPUC.

As we look at it, as a developer, the relevant long-term procurement plans that would be affected by this IEPR would be the 2006 and 2008 utility filings. This would involve requests for proposals that would be issued, we think, in the period 2006 through 2009, and maybe into 2010. And it would cover the resource period 2006 through 2018.

Now, based on our current analysis, IGCC as a technology, with or without sequestration, would not be competitive in the procurement that would be conducted pursuant to these two sets of filings.

In order to be considered by a utility in the context of these RFPs, let alone be competitive or successful in winning a contract, any IGCC project would have to meet availability

and performance guarantees that would be specified by the utilities under the terms of their plans and under the terms of their RFPs.

This would typically, we anticipate, require a performance guarantee on behalf of the developer amounting to something in the order of a 95 percent availability guarantee during periods of peak demand. Now it could be higher. It's not unheard of for that availability requirement to be 100 percent at peak, which simply means that if the plant isn't operating during those periods we are responsible for the incremental costs of replacement power or capacity.

Now, when we discuss these kinds of guarantees with IGCC contractors and technologists, we actually never reach the point of discussing price. The technologies are just not sufficiently mature that people have confidence that these guarantees can be provided, let alone priced, assuming the use of water-heavy, ash-laden and low-ranked coals available in the west.

We anticipate that these guarantees will be provided at some time in the future, probably in the seven- to ten-year window, but if

California specifies if IGCC -- and again, with or without CO2 sequestration, is going to be the only coal-fired technology that is permitted into the California resource mix, there will be no coal-fired resources added to the utilities' portfolios, whether by contract or ownership until 2015 at the earliest, in the absence of the provision of substantial financial guarantees to the developers, and along the lines of eliminating those availability guarantees that I talked to earlier.

This means that we probably put off until 2010 discussion of the addition of coal-fired resources in the utilities' long-term procurement plans. This, in our minds, results in the sacrificing of goals related to maintaining reasonable rates capturing the benefits offered by domestic coal resources, avoiding over-dependence on natural gas as a fuel, and assuring that new capacity is added to the mix of California resources prior to 2016.

Now, a viable alternative during these interim years to waiting for IGCC or providing the financial kinds of incentives that I talked about is to take the view described in the chapter 9

discussion of climate change and that has been discussed in the memorandum provided by Chairman Desmond to the Committee.

And that's specifically to provide a flexible means by which more conventional commercially available coal-fired generation could be added while still meeting environmental objectives. And that's why Sempra Global strongly supports the development and implementation of a multi-sector, geographically unbounded offset market as the means to balance the six goals that I mentioned earlier without sacrificing any one for the sake of another.

Now, I'm going to use Sempra's proposed Granite Fox project as an example, but I want to make sure that we understand that the discussion over whether offsets should be permitted is not about whether Granite Fox will or will not be developed, or whether Sempra Global will or will not make money.

The economics and location of the Granite Fox project simply make it extremely attractive to any number of wholesale buyers, many of whom are beyond the reach of either the CEC or the CPUC.

In terms of the policy recommendations that we have seen, and more recently that were adopted by the California Public Utilities Commission, we're at Sempra Global actually financially conflicted. We have a substantial fleet of uncommitted combined cycle combustion turbines whose capacity just got more valuable as a result of the CPUC's action. What we are sort of comparing that against is the loss margin that we might get from a coal project in terms of energy deliveries, as against state gas-driven energy market.

In any event, what we think is really open to discussion in terms of debating whether offsets should be permitted or not permitted is whether California will permit its utilities to capture directly the benefits that coal projects can offer to the energy markets.

To meet the greenhouse gas standard that was posed by the Commission, the combined cycle gas-fired plant proxy, at Granite Fox we would need to mitigate about one-half of the total CO2 emitted by the plant.

Using the CPUC-adopted risk standard of $8 per ton of CO2 emissions, this would raise the

price of energy from the plant by about $3 to $4 per megawatt hour depending on the duty cycles that the plant was placed under.

Now, this is actually something that the project, itself, could absorb without harming its competitiveness in terms of other resources that might be offered to the California utilities. The greater the flexibility in the mitigation methods that California permits, the lower the cost impact that mitigation will have, and the more likely it is that the project could be added to the California resource mix.

In terms of evaluating an offsets program you should take some comfort in the fact that there are a lot of innovative mitigation methods that are emerging as the states, themselves, attempt to address greenhouse gas reductions. And these innovations should be encouraged.

Now, I wanted to talk to you about one with which we were acquainted not too long ago, and that would be the Climate Trust of Oregon. Under programs supervised by the Oregon Energy Facility Siting Council, the Trust solicits, on behalf of developers, proposals by which CO2

emissions from projects submitted for siting approval can be offset either directly at the project or indirectly through offsets.

The Trust is a nonprofit, independent organization. It offers its services to project developers. It covers the full gamut from solicitation, selection, verification and reporting back to the Siting Commission and other state authorities.

It has been able to achieve a cost of about $2.50 per ton of CO2 reduction, both in the form of direct mitigation and indirectly through offsets. This is an option that we would intend to explore if we were permitted to be a developer of a project that would enter into an agreement with a California utility.

And unlike turning the project away to be sold to non-jurisdictional entities, it would directly -- permitting us to use offsets in this manner is part of the contract -- would directly affect the total CO2 emissions at the plant and the California, or I should say, energy sector contribution of CO2 to greenhouse gas emission inventories.

One other matter that we are also

exploring actively at this time was mentioned by Mr. Ackerman, and that's production blending, coupling a renewable resource development with conventional coal projects as a mitigation method. So, we understand that there may be some controversy over whether if we do that the renewable credits would still be able to be used to meet the California renewable portfolio standards. We haven't done our economic analysis on whether or not that was an essential part of this or not.

But as we combine all of these different kinds of strategies, offsets, mitigation, direct and indirect, we're still at the point where coal can be competitive without harming the ability of California, through an energy policy, to try to reach the Governor's objective with respect to greenhouse gases.

And I'm sure you're aware, and we certainly are aware, of the view that the long-term procurement on restrictions that are being considered in this IEPR and that were adopted by the CPUC yesterday are part of the stop-Granite-Fox-program. Again, I will tell you, that project is going to find market regardless of the

California policy.

And it still may find California market even if the policy is adopted, because as we know, the CPUC is about to adopt a capacity program under its resource adequacy requirement. There will be a need for the utilities to firm their renewable requirements under the resource adequacy rules. Whether that's done through contracts of less than three years, or a year ahead as contemplated under the current rules, or a month ahead, we think that Granite Fox can fit that bill, as well.

And it would escape the policy, which is, you know, sort of an uncomfortable evasion for us, but nevertheless, supports the project.

And again, as I said, in terms of the energy dispatch we think that Granite Fox, under its current configurations, and whether or not we include mitigation in the costs of operation of that facility, is obviously going to dispatch against a gas combined cycle, even if that combined cycle plant is supported by a long-term utility contract.

At $6 gas, we're four times -- gas dispatch is four times more expensive. At $8 it's

six times more expensive. Unless the ISO reforms its rules to effect an environmental dispatch as opposed to an economic dispatch, we suspect that this bar may not have the effect, if this is what's trying to be accomplished, of keeping Granite Fox or any other conventional coal project out of the California market.

As I said, we have financial interests on both sides of this policy. But we think that in the long run if we can pretend to own a public service interest, it is that California should consider using coal as part of its resource mix. And we think that there are strategies by which you can harmonize the use of coal using conventional pulverized coal technologies without harming the ability to achieve the Governor's objectives.

We're going to have some other comments that we'll file in writing with respect to the entire report. Again, let me go back to my opening remarks, this is an incredible piece of work. The fact that a lot of the recommendations are controversial, I think, are testament to the fact that you got the issues right. We didn't expect to see a whole lot of agreement around the

most controversial subjects.

But this is an extraordinary effort and you have considerably added to the progress we make in making our choices about what our future is going to be like.

So, if there are any questions I'd be happy to answer those.

PRESIDING MEMBER GEESMAN: Well, thank you for that detailed statement, Alan. I want to focus on what I'm sure you thought we would focus on, which is the greenhouse gas standard.

And numerically I do follow the rationale of your argument about achieving, or being able, with a pulverized project like Granite Fox, to, through mitigation and offsets, achieve the numerical aspects of the Governor's targets.

I'm also mindful of the fact that with respect to a lot of people there are reasons far beyond economics that govern their view or attitude toward the use of pulverized coal in the state's resource mix.

I want to focus on the financial question. The Public Utilities Commission, in their policy adopted in the December 2004 procurement decision, focused on the financial

risk of future carbon regulation. They set a number of $8 a ton of CO2. You indicated that the project's ability to absorb that level of financial risk.

My first question to you is what if that number is materially higher? When they chose $8 -

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MR. PAK: Yeah.

PRESIDING MEMBER GEESMAN: -- they were looking at a range of $8 to $25. I'm told that the deep ecologists of Idaho used a $12 proxy. What if it is $25, and your $3 to $4 a megawatt hour is, in fact, closer to $10 or $15?

MR. PAK: We would be out of the market. And let me tell you how we reached the conclusion. When we saw the PUC's range of $8 to $25, we were, at that point, thinking that California would be a primary market for this plant's capacity and energy.

So when the PUC said that any contract that would be signed with a coal project needed to take into account the future risks of CO2 regulation, and that the value of that financial risk was somewhere between $8 and $25, we ran scenarios to determine whether or not this project

was economic in the California market and whether we should proceed to continue with the development of the project.

At $8 we are competitive. At $25 we are not. That adds something in the order of $11 to $13 per megawatt hour to the cost of the dispatch. Somewhere between there, but obviously closer to the $8 level than the $25 level, we're sort of at a push.

So, depending on what the actual costs are, we can be in-market or out-of-market, at least with respect to California. And what we have spent a lot of time doing in the last six months is evaluating from a financial perspective, as well as a realistic perspective, of whether we could actually achieve costs lower than $8.

And as I said, we have found people coming to us who have provided us with strategies that are more economic than 8. Chicago Board of Trade figures are considerably below the figures I cited for the Oregon Trust.

Now, the question is whether the mitigation, whether the offsets that you would permit and recognize in California are the kinds that are traded and the kinds that the Trust can

effect.

We hope that this is the first of many dialogues about what can and can't be counted as an offset. And that would obviously affect the price. But so long as we could find a range somewhere close to the $8 and below say $10 to $12, I think we're still in-market and we don't frustrate your ability to achieve the Governor's goals.

PRESIDING MEMBER GEESMAN: But just to be clear, in that circumstance where the ultimate cost of carbon regulation did prove to be such that you'd estimate that you'd be out-of-market, I presume if the utility or the state were to achieve its fuel diversification or security objectives, that you would suggest that be a risk absorbed by the utility and its customers.

MR. PAK: Frankly, I don't think that we could have a serious discussion with a utility if future risk was unresolved, which is why it is our intended contract strategy to negotiate with the utilities so that they're confident that that risk is somehow expressed in terms of an allocation of the burdens of the risk between the developer as well as the utility.

PRESIDING MEMBER GEESMAN: So it would be something nailed down at the very outset?

MR. PAK: You know, at this point I'm sure I can speak for Robb. He wouldn't sign a contract unless it was addressed.

PRESIDING MEMBER GEESMAN: So, if the PUC really has captured the principal area of concern here, the prospect of future carbon regulation, and we go forward with a procurement policy that sets a greenhouse gas standard as the Committee draft has proposed it, but we do allow an offsets package to satisfy that standard, how can we be assured that some future carbon regulatory regime, whether it be regional or national or global in nature, will recognize those offsets, or grandfather that earlier agreement?

MR. PAK: You know, I don't think we can. But I think at that point, and I should have addressed this, I just note as a paragraph I had skipped.

Granite Fox and the new generation of conventional coal projects are still environmentally superior to the 1960s vintage of coal plants that are currently serving the utilities and the energy markets.

So when you get to the point where you're talking about a regime where CO2 and other greenhouse gases are going to be regulated, limited and reduced, we still think that we're in-market as compared to other legacy plants on which this procurement policy really doesn't reach.

So we think at that point there will be a reevaluation of what counts, how you operate under those restrictions. And we think that we're going to be competitively positioned as against other kinds of resources that are in-market.

PRESIDING MEMBER GEESMAN: Well, I certainly thank you for your comments. I want to compliment you for the detailed written comments that you've submitted to us in the past. And I'm hopeful that we can look forward to seeing comparable detail in what you turn in to us next week.

MR. PAK: I think you'll see that, yes.

PRESIDING MEMBER GEESMAN: Great.

MR. PAK: Thank you, Commissioners.

PRESIDING MEMBER GEESMAN: Thanks, again. Audrey Chang, NRDC.

MS. CHANG: Good morning, Chairman, Commissioners, Staff. Audrey Chang from the

Natural Resources Defense Council.

I'd like to just focus on three points today. I know we're running a little bit into the lunch hour, so I'll keep it brief. But I will focus on chapter 3 and the changes that we would like to see there. And we'll elaborate further in our written comments that we'll be submitting next week.

First, most importantly, we would urge the Commission to include in the IEPR a recommendation for next year and future IEPRs to examine the future resource mix that California will have with the collection of different resource fuel types on the resource plans of all load-serving entities.

As figure 6 on page 33 shows, the CEC expresses concern that despite current policies to diversify California's fuel sources, California supply is not diverse enough. And if we're concerned about today's diversity, then what's California's system going to look like in ten years.

Also on page 51, it notes that no one is considering the long-term economic impact on ratepayers. And that's exactly right. We need to

look at the future resource fuel types in order to make that assessment.

And these are the types of questions that a planning document such as the IEPR should be able to answer. What will the future resource mix for California look like; what costs do California ratepayers face; what risk does the state face; and what are the environmental impacts, greenhouse gases, et cetera. We haven't been able to answer this yet with the current data that's been collected.

What we are looking for as a generic analysis of fuel types on a state portfolio level to see what fuel types natural gas, conventional coal, IGCC, et cetera, are likely to emerge under current policies. And then we can determine if additional policies are needed to meet the state's policy goals.

We agree with the statement on page 45 that we can't know the specific plans that are out there, but that's not reason to do this analysis, but we can ask for projections and not necessarily the incremental purchase decisions.

This sort of analysis is parallel to forecasting natural gas prices, retail rates, et

cetera. We don't know the future, but there is a benefit in forecasting these values.

so, in conclusion, on that point we recommend that the IEPR look at -- future IEPRs look at true resource planning from looking at the statewide future energy mix by collecting information from all LSEs regarding their future resource fuel types.

The second point that I have is that we urge that the current IEPR clarify how energy efficiency is accounted for in the demand forecast. We acknowledge that the current forecast, the decision has been made is that energy efficiency is not incorporated beyond the 2008 point. But we do recommend that it is clarified whether or not PGC funds are included for post-2008. They should be at the very least, since that is legislatively mandated. And also whether or not future code updates are also included in the forecast.

Regardless, we also need to make it clear that a substantial portion of the state's growing load will be expected to be met by energy efficiency. It's about half the growing consumption is projected to be met by energy

efficiency.

And the third and final point that I have is that we urge future years IEPRs to perform analyses of bill impacts, not just looking at rates. In order to determine the true economic impacts on consumers, we need to look at the total bills they are paying, not just the rates that they are paying.

And with that, I'll conclude my comments. And we will definitely expand on them in our written comments.

PRESIDING MEMBER GEESMAN: Thank you very much. Bruce McLaughlin, California Municipal Utilities Association.

MR. McLAUGHLIN: Good morning, Commissioners. Just a couple quick comments.

First of all, yesterday I used biomass as a whipping boy, and I think I would like to clarify that certainly the munis believe that all resources that are low or no GHG are good resources. And so biomass is a great one, and I think I can safely say that we agree with all your recommendations on 103 and 104 of your IEPR here on biomass.

And then just a clarification we would

like on page 43 where it says the Energy Commission recommends that state policymakers provide a clear signal that all publicly owned utilities take on an explicit resource adequacy requirement. And I'm sure you're familiar with AB-380 which passed just a couple weeks ago, and it was passed since these words have been written.

So added to the Public Utilities Code 9620, one sentence here, each local publicly owned electric utility serving end-use customers shall prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves sufficient to provide reliable electric service to its customers.

Then below we have a minimum numerical standard which is WECC. We have an independent measurement mechanism, which is the IEPR. And then we have oversight where you take that IEPR and you give it to the Legislature, who's our boss. And they wrote these words.

So we do have exactly what you requested here. This, we do believe, is a good thing. And we have been following these standards. There might be -- well, I won't go there.

Thank you very much. I wanted to get that in the record.

PRESIDING MEMBER GEESMAN: Thank you, Bruce. Stuart Hemphill, Southern California Edison.

MR. HEMPHILL: Good morning, Commissioners. Appreciate the opportunity to speak again today. I'll be brief as I was yesterday.

I have some overall questions and then -- excuse me, some overall comments, and then some specific areas where I'd like some clarification in the report, itself.

I want to echo everything I heard, I think, from Gary Ackerman this morning regarding the role of coal and greenhouse gas policy for the State of California. I thought he spoke of it very well, and I was trying to find some area where I disagreed with him, and I could be wrong, but I didn't find any.

I also appreciated the comments of Greg Blue, who mentioned some of the issues that we had related to trying to make sure that there's adequate supply. He talked about the missing megawatts. And we took actually the supply and

demand analysis from this Commission as our platform to seek new resources on behalf of southern California.

So we tried to step up, but the CPUC told us it was not our responsibility. and the ultimate question that I think California does need to address is who is responsible for assuring resources are available for grid liability. It is an important issue. It's something that we need to address. I'm not sure how that fits into this IEPR process, but it's something that is very critical for the State of California.

Secondly I wanted to talk a little bit about -- all of my specific issues relate to chapter 3 in your report. I want to talk about the retail electricity market. In California it's comprised of many retailers; we call them load-serving entities here.

As a retailer who is 70 percent reliant on contracts to meet customer needs, we cannot feel very confident or comfortable giving generators and marketers market-sensitive information related to quantity, price and contracting terms. We've seen long histories of that kind of information being provided to

generators and marketers. And its ultimate effect is increased prices for customers. That's as much as I'm going to say on that topic. And I'm sure you appreciate that.

Two areas of clarification in the report. The first is on page 32. It indicates IOUs focus on near- and mid-term contracts which perpetuate reliance on existing resources. What I'd like to see there is a recognition that all load-serving entities currently focus on mid- to medium-term contracts. And as far as I know, electric service providers in California exclusively rely on short- to medium-term contracts.

PRESIDING MEMBER GEESMAN: Now, were you here for Mr. Anderson's remarks?

MR. HEMPHILL: Yes, I was.

PRESIDING MEMBER GEESMAN: Don't they contradict what you just said?

MR. HEMPHILL: In what way?

PRESIDING MEMBER GEESMAN: Long-term contracts.

MR. HEMPHILL: Oh, the second point is that the IOUs are the only ones offering long-term contracts as far as I know. So those are my two

main points related to --

PRESIDING MEMBER GEESMAN: Some of the IOUs.

MR. HEMPHILL: Well, we certainly are doing that. We've done quite a bit of that over the last several years as we've increased our renewable --

PRESIDING MEMBER GEESMAN: That's correct.

MR. HEMPHILL: -- resources. I don't know of any electric service providers who are doing the same thing.

And finally on page 47 there is a discussion that says greater disclosure is warranted for IOUs because they are regulated monopolies. I just wanted to footnote or some clarification, the retail business is not a monopoly, which is a big part of contention. And one of the reasons why it is critical that we maintain confidentiality of information.

So, if there is some clarification that just points out, you may not agree necessarily with my points of view on this, but if there's some recognition that the retail business is not a monopoly, I'd appreciate that.

Those are my comments.

PRESIDING MEMBER GEESMAN: Thank you, Stuart. Those are all the blue cards that I have. Is there anyone else in the audience that cares to address us this morning before our lunch break?

Is there anybody on the telephone?

Okay, we're going to recess then for lunch. We'll come back at 1:00 and take up the natural gas issues.

(Whereupon, at 12:05 p.m., the hearing was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 12th day of October, 2005.